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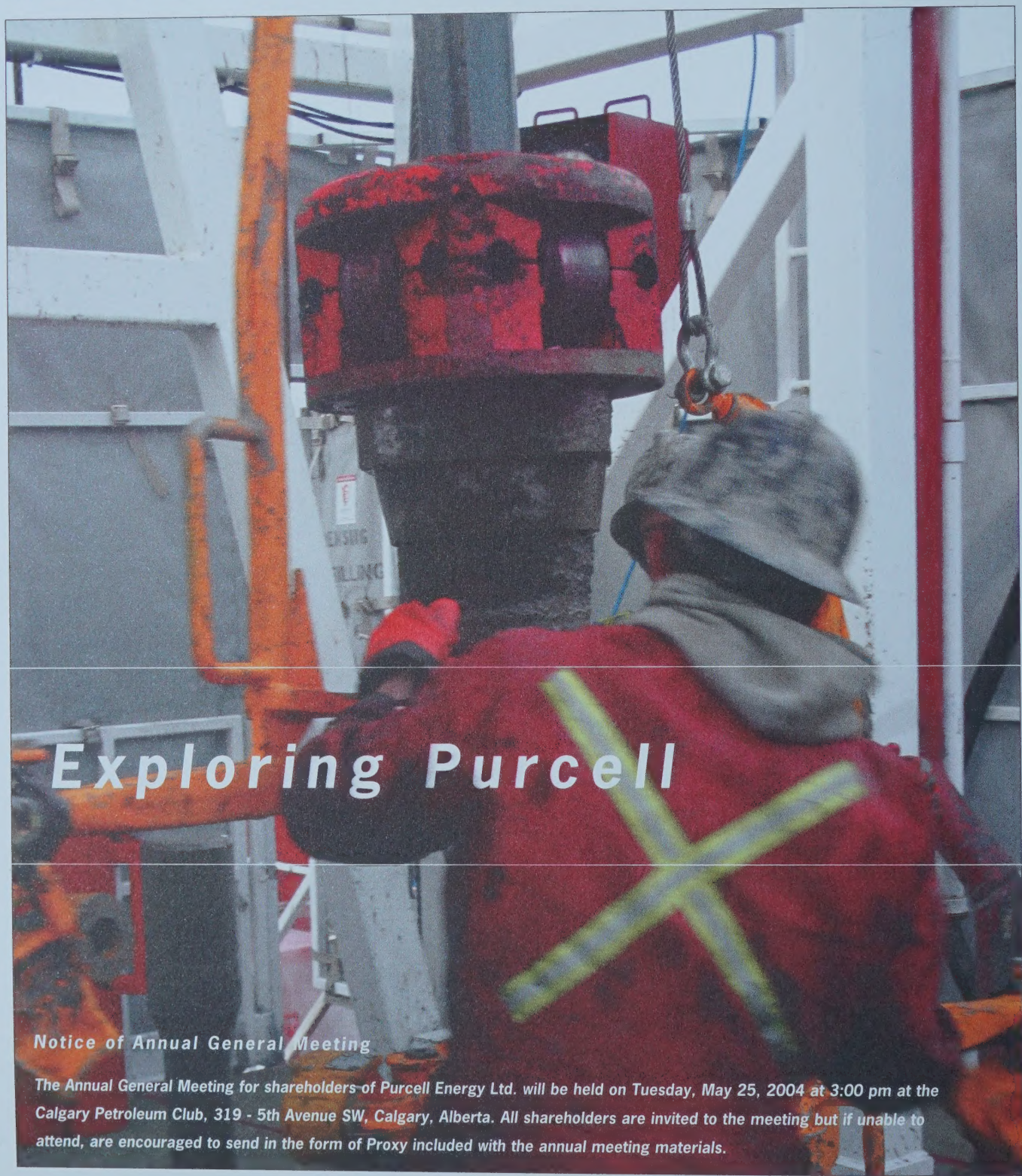
purcell energy ltd.

Exploring Purcell

Corporate Profile

Purcell Energy is a dynamic Canadian junior oil and gas exploration and production company. Purcell stands out as one of the few companies its size focused on technology-driven exploration and deep natural gas wells.

Building on the strength of its Fort Liard natural gas discovery in the Northwest Territories, Purcell is actively drilling exploratory and development wells throughout the Western Canadian Sedimentary Basin. The Company is broadening its production base and seeking growth through exploration.



Exploring Purcell

Notice of Annual General Meeting

The Annual General Meeting for shareholders of Purcell Energy Ltd. will be held on Tuesday, May 25, 2004 at 3:00 pm at the Calgary Petroleum Club, 319 - 5th Avenue SW, Calgary, Alberta. All shareholders are invited to the meeting but if unable to attend, are encouraged to send in the form of Proxy included with the annual meeting materials.

2 Message to Shareholders 6 Report on Activities 14 Management's Discussion and Analysis 32 Financial Statements and Notes IBC Corporate Information

($000, except where indicated, 6 mcf = 1 bbl)	3 months to Dec. 31			12 months to Dec. 31		
	2003	2002 (Restated)[3]	% change	2003	2002 (Restated)[3]	% change
Financial						
Petroleum and natural gas sales	**15,776**	9,978	58	**50,389**	30,746	64
Revenues, net	**12,367**	7,465	66	**38,787**	26,677	45
Production expenses	**3,870**	2,353	64	**10,894**	7,880	38
Per unit ($/boe)	**7.44**	6.83	9	**7.07**	5.37	32
G&A expenses	**1,092**	405	170	**3,212**	2,195	46
Per unit ($/boe)	**2.10**	1.17	79	**2.09**	1.49	40
Cash flow	**6,343**	3,962	60	**21,217**	14,677	45
Per share - basic ($)	**0.132**	0.150	(12)	**0.618**	0.554	12
Per share - diluted ($)	**0.132**	0.148	(11)	**0.618**	0.544	14
Net income (loss)	**(1,623)**	(201)	(705)	**1,696**	982	73
Per share - basic ($)	**(0.034)**	(0.008)	(325)	**0.049**	0.037	32
Per share - diluted ($)	**(0.034)**	(0.008)	(325)	**0.049**	0.036	36
Capital expenditures, net [2]	**8,819**	6,131	44	**32,693**	35,232	(7)
Net Debt				**56,794**	40,176	41
Common shares outstanding						
Weighted average - basic	**47,881**	26,400	81	**34,330**	26,491	30
Weighted average - diluted	**47,882**	26,818	79	**34,331**	26,973	27
End of period - basic				**50,090**	27,641	81
End of period - fully diluted				**62,209**	31,179	100
Operations						
Production						
Natural gas (mmcf/d)	**26.68**	17.28	54	**20.15**	19.56	3
Crude oil and liquids (bbls/d)	**1,209**	864	40	**862**	763	13
Equivalent (boe/d)	**5,656**	3,745	51	**4,220**	4,022	5
Product prices (well head) [1]						
Natural gas ($/mcf)	**4.86**	4.19	16	**4.81**	3.06	57
Oil and liquids ($/bbl)	**34.66**	35.57	(3)	**37.44**	34.56	8
Equivalent ($/boe)	**30.35**	27.56	10	**30.61**	21.45	43
Operating net back ($/boe)	**16.33**	14.84	10	**18.11**	12.79	42
Cash flow net back ($/boe)	**12.19**	11.50	6	**13.77**	10.00	38

[1] Product prices include hedges, and transportation costs are deducted.
[2] Excludes the cost of corporate acquisitions.
[3] Restated due to the retroactive application of the change in accounting policy for asset retirement obligations pursuant to CICA S. 3110.

repositioned for growth

THIS YEAR'S ANNUAL REPORT IS MORE THAN FACTS AND FIGURES. IT IS AN OPPORTUNITY FOR PURCELL TO REPORT ON ITS EXPLORATION AND AN INVITATION TO READERS TO EXPLORE PURCELL.

In the pursuit of large gas reserves, Purcell has chosen what many might think is an old-fashioned approach. The Company's strategy is a patient, long-term plan to methodically look for deep, large gas deposits that can truly be "company makers". To accomplish this, Purcell seeks to build land positions in prospective unexplored regions of western Canada. This approach is in sharp contrast to the strategy pursued by many other successful junior oil and gas companies who have increased production by aggressively drilling wells on or near existing oil and gas pools. We believe that by pursuing a unique exploration strategy we will reap substantial rewards for our shareholders in the long term.

We understand that pursuing a full-cycle high-risk exploration strategy may take several years to achieve success. Drilling deep exploration wells means that each well carries a significant risk of being dry. We also understand that success on as little as one or two of Purcell's high-impact exploration plays will have a significant positive impact on the Company. Over the past year, we have moved ever closer to achieving this success.

In recognition of the risks associated with deep exploration drilling, Purcell strives to balance its portfolio of projects by diversifying into lower-risk ventures that generate production and cash flow to finance our more ambitious projects. The acquisition of BelAir Energy in September 2003 was a strategic move to quickly gain moderate-risk drilling and exploitation opportunities to complement Purcell's higher-risk exploration activities.

The Purcell plan

Implementation of Purcell's long-term strategic plan during 2003 led to growth and enhanced stability of production and cash flow – and brought us closer to our ambitious goal of another large discovery. The Purcell story unfolds as the pages are turned on each of the plan's five chapters:

1. **Exploration:** Purcell grows reserves and production through full-cycle exploration and development in the Western Canadian Sedimentary Basin. Among the best examples of this is our Slave Point natural gas play at Tenaka, near Adsett in northeast British Columbia. Covering 55,000 gross acres, this play has reached the drilling phase after Purcell spent three years building its land position and 3D seismic base.

   In 2003, Purcell successfully drilled, on a gross basis, 21 natural gas and four oil wells. Of Purcell's wells drilled during the year, 16 are considered exploration wells, and four were looking for deep natural gas reserves. In the first quarter of 2004, the pace has accelerated as the Company drilled 11 wells, which resulted in four gas wells, four potential gas wells, one oil well, and two dry holes.

2. **Acquisitions:** As part of our goal to acquire value-adding producing properties with good potential for optimization, exploitation and development, we completed the acquisition of BelAir Energy in September 2003. Terms of the acquisition were fair to both companies with Purcell and BelAir each valued at their respective net asset values. The deal provided Purcell with a broader reserve and production base – and that base will help Purcell fund its extensive exploration and development program.

   The acquisition of BelAir accounts for about one-third of Purcell's reserves, bringing stable production and lower-risk plays, as well as opportunities for growth that the capital-constrained BelAir was unable to pursue.

3. **Technology:** We fully utilize available exploration tools and technology such as hydrocarbon remote sensing and existing trade 2D seismic data to screen play concepts. We then typically follow-up with the acquisition of 3D seismic data to reduce risk. In the past year, we have enhanced our ability to capitalize on technology by strengthening our in-house geophysical, engineering and land expertise so we can generate more plays and proceed expeditiously.

4. **Partnerships:** We partner with senior companies that are experts in our areas of operation to manage risk, enhance Company knowledge, and reduce competition. The benefit of such partnerships is that Purcell works with companies that have developed expertise in certain areas. These companies also have good access to capital, technology and oil and gas services.

5. **Financing:** Purcell uses a prudent combination of debt and equity to finance growth. In 2003, the Company raised $30.7 million in new equity and increased its bank line to $65 million, of which $52 million was drawn at the end of 2003. While a combination of debt and equity has been used to finance acquisitions, our drilling is normally funded directly from our cash flow. This lowers the corporate risk associated with aggressive natural gas exploration.

Where do these activities position Purcell as it moves through 2004? We are poised to pursue outstanding opportunities with an excellent team, exciting plays and a broadened base of production and reserves to support our growth.

The next chapter of our growth

Our balanced drilling program will see us participate in drilling approximately 40 gross wells in 2004 – a record number – with a capital budget of $32 million. This carefully constructed program will encompass:

- Low-risk oil projects in southeast Saskatchewan.
- Low- to medium-risk gas exploration programs in west and central Alberta.
- High-risk exploration for deep gas in northwest Alberta and northeast British Columbia.
- High-potential-reward development wells at Fort Liard.

Tenaka. In keeping with our philosophy of seeking large gas reserves, we had the foresight to identify this area in northeast British Columbia as possessing vast potential for large, deep structures containing natural gas reserves. The opportunity has since been amplified by robust gas prices, and by successful drilling of a number of significant wells on an adjacent property. Purcell has partnered with a large U.S. independent exploration and production company. This company operates the adjoining Adsett property and has expertise in the area. Prior to spring break up in 2004, two wells were drilled to depths of 2,700 and 3,000 meters and logged. The wells are suspended as potential gas wells pending completion and testing next winter. Unseasonably warm temperatures caused loss of access over the winter roads and prevented the operator continuing operations. Positive indications from this winter's program confirm Tenaka is a very promising area for Purcell's future growth.

Fort Liard. In western Canada, the average natural gas well produces at a rate of less than 0.25 mmcf/d. In sharp contrast, the initial four wells from the Fort Liard gas pool have generated aggregate gross production of 114 billion cubic feet of raw gas (81 billion cubic feet of sales gas) at raw gas production rates ranging from 10 to 70 mmcf/d since coming on production in May 2000. A fifth well drilled in the first quarter of 2004 must be sidetracked to a modified bottom-hole location in order to achieve the high production rates we have grown accustomed to in the area. Meanwhile, a second development well that is currently being drilled is expected to come on stream during the third quarter. In addition to the four original wells and the two being drilled during the first half of 2004, three more locations have been identified for potential drilling to further develop the large gas reserves.

Doris. Purcell has recently tied in four natural gas wells in the Roche area of Doris, Alberta (34 percent working interest) raising the Company's net production from 400 boe/d to 700 boe/d for the area. A new 40-kilometre pipeline built by Purcell will enable the Company to produce from future wells drilled over the next few years on its large undeveloped land position. Purcell holds working interests ranging from 34 to 56 percent in approximately 187,000 gross acres, including recent land purchases, in the greater Doris area.

Other recent successes. First-quarter successes include oil and gas wells plus several tie-ins, adding production in the West Pembina area of Alberta, and at Tatagwa in southeast Saskatchewan. Purcell's drilling program has also produced recent successes at Obed, Blueberry and Pigeon Lake, Alberta.

More detailed information on Purcell's properties and drilling is found in the Report on Activities section of this report.

Exploring Purcell

Purcell is well-funded and diversified with high-potential opportunities, strong partnerships and a promising future. Thank you for accepting our invitation to explore Purcell and find out what the Company is all about through this annual report. As we move confidently through 2004, we hope you will find your relationship with us rewarding.

I would like to extend my appreciation to our committed board of directors, all our supporters and to our dedicated employees who have made the Company what it is today and will be instrumental in ensuring its future success.

On behalf of the board,

Jan Alston

President and Chief Executive Officer

April 8, 2004

A SOLID BASE

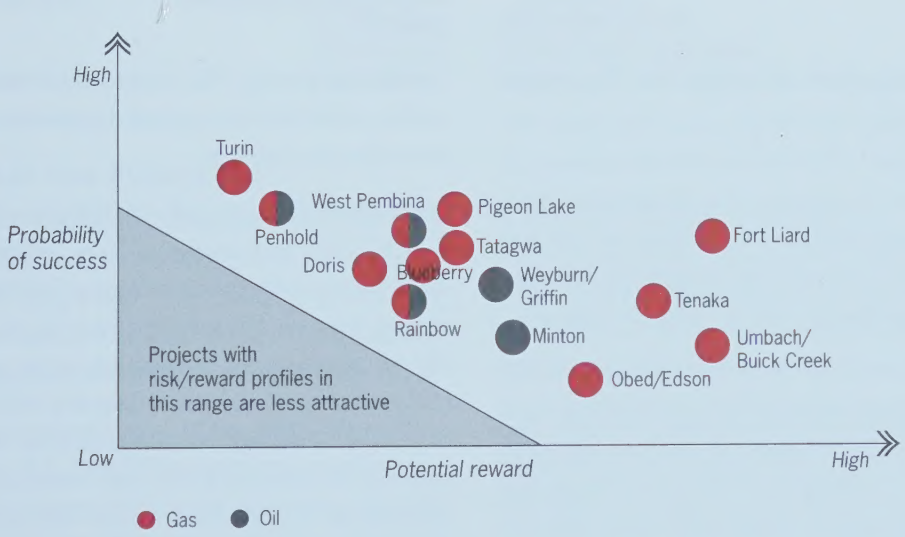
- SEVEN KEY PRODUCING PROPERTIES
- 328,000 NET ACRES OF UNDEVELOPED LAND
- REPOSITIONED WITH MORE YEAR-ROUND ACCESS AND COMPANY-OPERATED PROPERTIES

looking for high impact reserves

In 2003, Purcell broadened its operating and production areas. Purcell's focus remains on exploring for the next big natural gas discovery, but now the Company has a larger base to support its pursuit of this goal.

Purcell's numerous exploration and production areas now include more properties with year-round access. Although the Company's high-impact opportunities are mostly in areas dependent on winter access, Purcell is better positioned to remain active throughout the year. This should lead to steadier production growth. As shown in the diagram below, the Company's properties provide a diverse range of opportunities from high-risk, high-reward to low-risk, moderate-reward plays. The effect of this diversification is particularly significant because it means Purcell has more low-risk opportunities that will ensure production growth and provide cash flow for ongoing exploration.

Purcell operates approximately 40 percent of production, up from about 25 percent in 2002. This is mostly a result of the acquisition of BelAir Energy, which operated 80 percent of its production. Senior oil and gas companies operate many of Purcell's other properties. Although the Company has less influence on the timing of activities, this is beneficial because senior companies generally have excellent technical expertise.

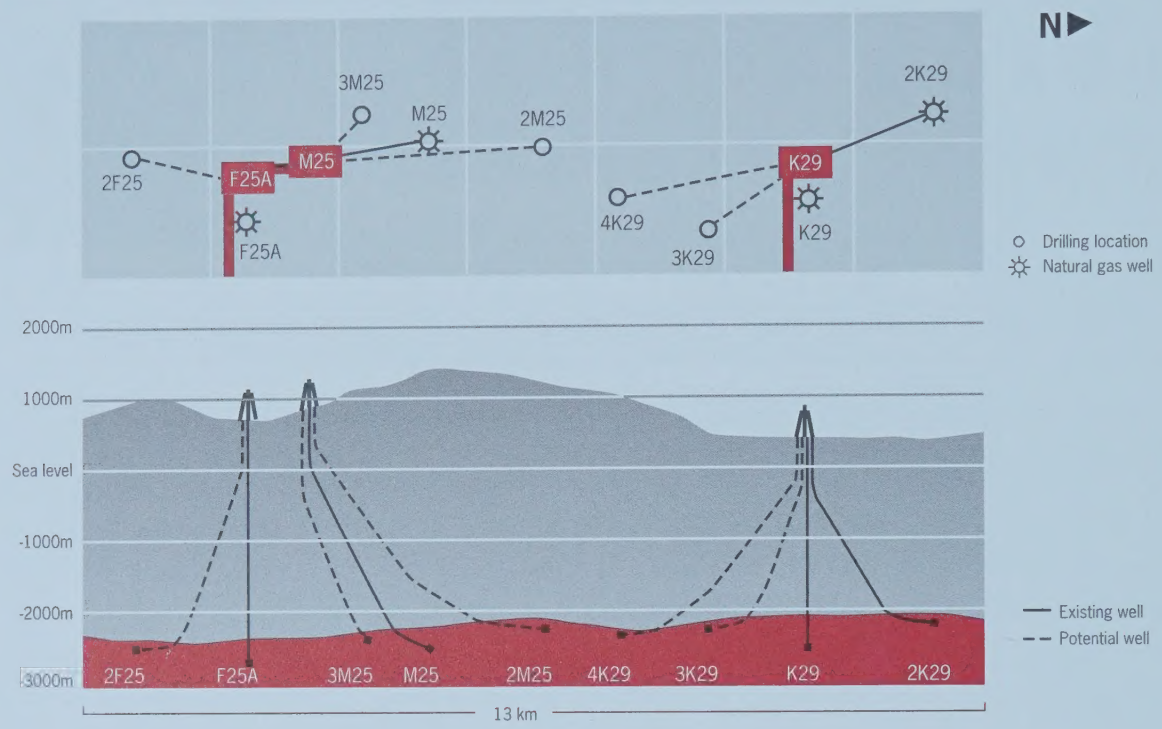


Undeveloped Land

Consistent with Purcell's full-cycle exploration strategy, the Company is an active purchaser of exploration acreage in central and northern Alberta and in northeast British Columbia. Using various exploration tools, Purcell has acquired significant land positions at a reasonable cost in several high-potential-reward areas.

At the end of 2003, Purcell's undeveloped land position stood at 329,000 net acres compared with 190,000 net acres one year earlier. This land position provides excellent potential to add value for Purcell and its shareholders.

Fort Liard, Northwest Territories



Gross land position:	12,775 acres
Net land position:	3,354 acres
Average working interest:	26 percent
2003 producing wells:	4 natural gas
2003 average net production:	12.89 mmcf/d (2,148 boe/d)
Operator:	third-party senior

High-Impact Development of Large Gas Reserves

In early 2003, Purcell drilled the 2K-29 well at Fort Liard. The 2K-29 was drilled to a bottom hole location at I-40 northwest of the original K-29 well. Since being placed on production in May 2003, the 2K-29 well has produced at an average raw gas rate of 25 mmcf/d. This is a restricted rate designed to optimize recovery of the pool's natural gas reserves over the long term.

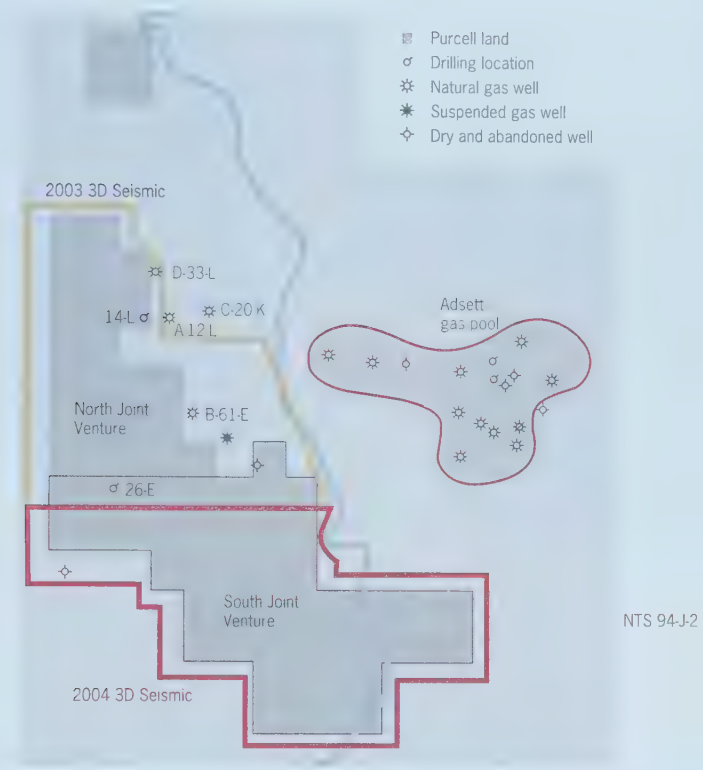
Purcell also produced natural gas from three other previously producing wells at Fort Liard during 2003. From the first natural gas production in May 2000 to December 31, 2003, the four wells at Fort Liard produced an aggregate of 114 bcf of raw gas (81 bcf of sales gas). All wells produce natural gas from the Nahanni formation (middle Devonian).

The Fort Liard area was initially identified by Purcell and its predecessor company over ten years ago as having potential for large natural gas reserves. Purcell farmed out the play to a senior oil and gas company in the late 1990s. As operator, the senior producer has taken a conservative approach to the development of the property. Purcell has supported a more aggressive development strategy. At the end of 2003, the operator announced its intention to sell its interest in Fort Liard (along with other Canadian properties). The proposed sale is positive for Purcell as it has already led to accelerated optimization of the property's production and reserves.

The 3K-29 development well was drilled to a bottom-hole location at O-28 in the first quarter of 2004, followed by drilling the 2M-25 well to a bottom-hole location at D-27 in the second quarter of 2004. Pressure and test data from the 3K-29 well confirmed that the horizontal leg is connected to the main Fort Liard gas pool, but the well bore did not intersect sufficient open fractures to produce at the high rates expected for this well. The 3K-29 well will be sidetracked to a new bottom-hole location during the summer of 2004 when Purcell anticipates both wells will come on stream, having a significant impact on the Company's production levels in the latter half of 2004. There is also potential to drill three more development locations that have been identified by Purcell and the current operator.

Purcell continues to pursue additional opportunities in the greater Fort Liard area. The Company is exploring a 5,000-square-km area in the southeast Northwest Territories and southwest Yukon Territory, focusing on deep gas prospects. Purcell hopes that with the support of the Fort Liard community, long-awaited land sales will occur in the area. Purcell is in a strong competitive position to build on its Fort Liard success.

Tenaka, Northeast British Columbia



Gross land position:	51,230 acres	2003 producing wells:	0
Net land position:	23,267 acres	2003 average net production:	0 boe/d
Average working interest:	45 percent	Operator:	third-party senior

High-Impact Deep Gas Exploration

The Tenaka play represents the culmination of a full-cycle exploration project that has taken three years to proceed from inception to the drilling stage. This involved preliminary technical work to determine the area's potential, followed by an ambitious land acquisition strategy to secure a key position.

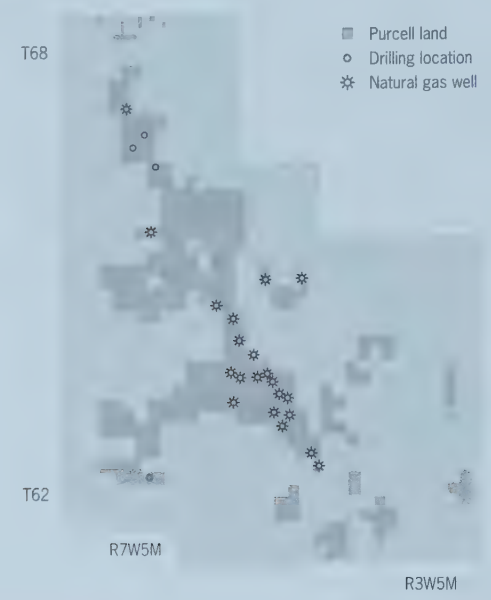
Tenaka is located immediately west of the Adsett Slave Point gas pool in northeast B.C. Purcell has negotiated two farm-out and joint-venture agreements with a senior oil and gas company covering almost all of Purcell's land in the area, a total of 71 gas spacing units (49,000 gross acres). Purcell's joint ventures combine the Company's expertise with its partner's specific technical experience in this area and its ownership of the adjacent infrastructure. Gas produced from the joint venture lands will be processed through the joint venture partner's existing Adsett infrastructure under favourable terms.

During the first quarter of 2004, Purcell participated in the first two wells drilled and logged on its joint venture lands. Purcell paid 25 percent to retain a 37.4 percent interest after payout of costs for the first well, (b-14-L). On the second well, (a-26-E) Purcell has a 28 percent working interest. The wells are testing two Slave Point gas prospects out of many identified by a 120 km2 3D seismic program shot in early 2003 over Purcell's north block.

Both wells have been suspended as potential gas wells pending completion and testing next winter. Unseasonably warm temperatures caused loss of access over the winter roads and ice bridge and prevented the operator from testing and completing the wells. Positive indications from this winter's program point to more wells being drilled at Tenaka next winter. This continues to be a very promising area for Purcell's future growth.

A second 162 km2 3D seismic survey, (approximately one-third interest), is being completed over the south block and will be used to determine potential drilling locations for next winter. Drilling success in Tenaka could lead to a multi-year, multi-well exploration and development program.

Doris, Central Alberta



Gross land position:	186,880 acres
Net land position:	95,817 acres
Average working interest:	51 percent
2003 producing wells:	21 natural gas
2003 average net production:	1.96 mmcf/d natural gas and 7 bbls/d NGLs (334 boe/d total)
Operator:	Purcell

Step-out Exploration and Development

The property at Doris, northwest of Edmonton in central Alberta, was BelAir Energy's primary producing property. The southern portion of the Doris property has year-round access while the northern portion is winter-access only.

Purcell continues to add to its position in the area through land purchases. Based on 2D seismic data, Purcell identified a large number of gas prospects in the Roche area of the North Doris lands and drilled three exploratory wells (34 percent interest) in the first quarter of 2004. These wells followed up on a previous discovery drilled in 2002. The drilling program resulted in one gas well, one potential gas well and one dry hole.

A total of four wells, including three previously suspended gas wells, were tied in to a new 40-kilometer pipeline constructed by Purcell in March 2004. The pipeline connects the wells to Purcell's 28 percent-owned Doris South gas plant. The new gathering line will enable the Company to produce from future wells drilled on its large undeveloped land position over the next few years. The successful completion of Purcell's winter program in the Doris area has added gas production as of April 1, 2004. The Company's net production from this area now exceeds 700 boe/d compared to 400 boe/d in the fourth quarter of 2003.

Rainbow, Northwest Alberta

Gross land position:	16,800 acres
Net land position:	13,586 acres
Average working interest:	81 percent
2003 producing wells:	4 natural gas, 8 oil
2003 average net production:	0.92 mmcf/d natural gas and 115 bbls/d oil & NGLs (268 boe/d total)
Operator:	Purcell

Multi-zone Oil and Natural Gas Production

Rainbow is an oil and natural gas development area located in northwest Alberta near the town of Rainbow Lake. Purcell began operations there in 2001, pursuing natural gas, crude oil and NGL prospects with a joint-venture partner. In addition to five wells drilled in 2001 and 2002, the Company constructed an oil battery and a 14-kilometer gathering pipeline for sour gas in 2002.

Purcell's production in this area in 2003 was restricted by problems at a third-party gas plant. This plant was recently sold and the new owner has committed to increasing Purcell's throughput. Modifications to the gas plant should enable Purcell to increase production starting in the third quarter of 2004. Purcell is continuing to pursue additional drilling opportunities in this core area through a joint venture with a senior oil and gas company on lands in which Purcell holds a 50 percent interest.

West Pembina, Central Alberta

Gross land position:	14,240 acres
Net land position:	6,403 acres
Average working interest:	45 percent
2003 producing wells:	One natural gas, two oil
2003 average net production:	0.05 mmcf/d natural gas and 8 bbls/d oil and NGLs (16 boe/d total)
Operator:	third-party junior

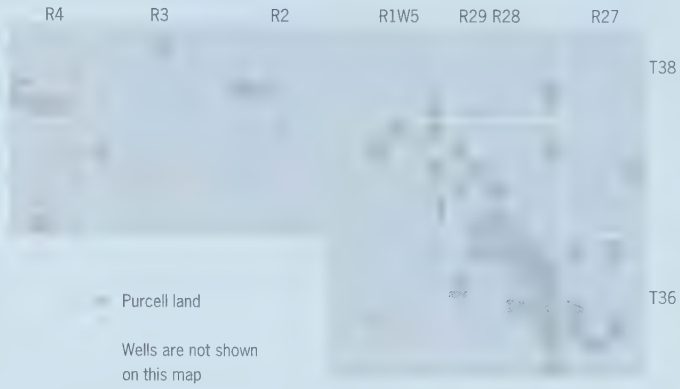
Impressive Drilling Success Rate Adds Reserves

West Pembina, located just west of Edmonton, offers multi-zone, long-life reserve potential for liquids-rich gas and light oil. Through the drilling of relatively low-risk wells in 2003, Purcell has turned West Pembina into a new core area.

West Pembina offers year-round access, good infrastructure and drilling at a reasonable cost. To date, all of Purcell's wells in the area have been drilled vertically to a medium depth. As a result, this area provides low-cost reserve additions.

Purcell has tied in four 50 percent-interest wells drilled since mid-2003 in West Pembina. A fifth well should be tied in later this year. The wells are producing a total of 130 boe/d net to the Company from various horizons. An additional 130 boe/d net is presently constrained and is expected to be producing later in the second quarter. At least six additional wells will be drilled in the second half of 2004. Purcell continues to build its prospect inventory in the West Pembina area.

Penhold, Central Alberta



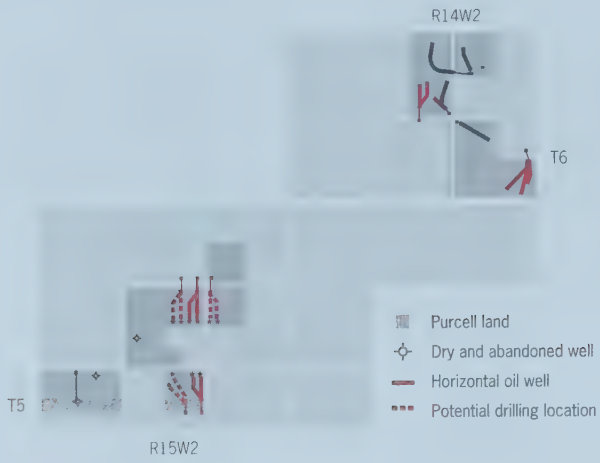
Gross land position:	31,145 acres
Net land position:	17,090 acres
Average working interest:	55 percent
2003 producing wells:	24 natural gas, 10 oil
2003 average net production:	1.07 mmcf/d natural gas and 64 bbls/d (243 boe/d total)
Operator:	Purcell

Potential of Area is Under Review

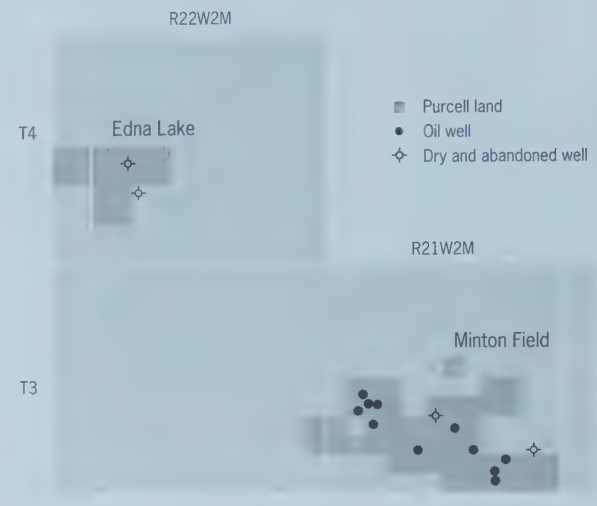
Purcell obtained its core area in Penhold, located just south of Red Deer, Alberta, through the BelAir acquisition. Purcell operates the oil and natural gas producing wells, as well as natural gas processing facilities. Penhold has good Edmonton Sands shallow gas potential. The area boasts year-round access as well as proximity to major pipeline and transportation routes.

Purcell is reviewing its plans for the area and meanwhile continues to work with its partners to exploit the existing production base with infill drilling and optimization activities.

Southeast Saskatchewan



Weyburn, Tatagwa and Griffin



Minton

Gross land position:	45,079 acres
Net land position:	22,633 acres
Average working interest:	50 percent
2003 producing wells:	35 oil
2003 average net production:	445 bbls/d oil (445 boe/d total)
Operator:	Purcell

Purcell's Original Bread and Butter

Southeast Saskatchewan has been a core area for Purcell since 1997. The relatively stable production has helped Purcell maintain sufficient steady cash flow to continue exploring for large reserves in other areas. Purcell continues to actively develop its lands in southeast Saskatchewan with the help of in-depth knowledge and many years of experience.

Weyburn, Tatagwa and Griffin

At Weyburn, Purcell operates wells (50 percent interest) producing oil in the Midale formation, and is working to continue development in the area. A recently drilled horizontal well (100 percent interest) will be tied in by the second quarter of 2004.

At Tatagwa, Purcell drilled a dual-legged horizontal development oil well (100 percent interest) into the Marly formation in March 2004. The well was subsequently placed on production and if the initial oil production rates of 100 bbls/d continue, Purcell has several follow-up development locations.

At Griffin, the Company has two successful horizontal wells, and has acquired more land where it intends to continue drilling for oil.

Minton

Purcell's operated property at Minton consists of a 100 percent interest in 9,120 acres and an oil facility. The wells at Minton are producing light crude oil from both the Red River and Winnipegosis zones. The Company is expanding the fluid capacity of the facility to support further exploitation of the existing producing wells. Purcell plans to continue development in this area and pursue exploration prospects in nearby Edna Lake.

Additional Exploration and Development Areas

Milo, Muskwa and Clarke Lake, Northeast British Columbia

Land position: 12,803 gross acres, 2,075 net acres
2003 net production: 1.86 mmcf/d (310 boe/d)
Operator: Purcell and third-party junior

At Muskwa, the inability to obtain a rig and the early arrival of spring in 2004 prevented a work over of a 28 percent-interest well on this Slave Point gas property in northeast British Columbia. This has reduced production from this area by about 200 boe/d until operations can be completed next winter. A 10 percent-interest horizontal gas well drilled at Milo in January 2004, currently producing at 600 boe/d (60 boe/d net), has replaced some of this production.

Additional optimization opportunities exist on these properties which will be pursued in the first quarter of 2005.

Umbach, Northeast British Columbia

Land position: 18,355 gross acres, 4,058 net acres
Operator: third-party senior

At Umbach, several untested structures exist on Purcell's acreage, which is adjacent to some large natural gas discoveries made in the past couple of years. Purcell drilled a potentially high-impact well during the third quarter, which was unsuccessful at discovering economic production and reserves in its deep Slave Point target. However, the two wells drilled on the project have identified shallower gas potential. Purcell and its partners continue to review the drilling results and their 130 km2 of 3D seismic to determine if there is potential to sidetrack the latest well. The Company plans to move forward on the shallow gas development in 2004.

Blueberry, West Central Alberta

Land position: 10,078 gross acres, 1,992 net acres
Operator: Purcell

Purcell successfully drilled a 50 percent-interest gas well at Blueberry in the first quarter. The well was completed and production tested. The plan is to tie in the well by the end of the second quarter of 2004. A second exploratory well was recently drilled on an exploratory prospect (50 percent interest) in this area targeting the Kiskatinaw formation. Completion and testing of this well will begin immediately following spring breakup. Another prospect is being developed in the Blueberry area and could be drilled in the third quarter of 2004.

Lochend, West Central Alberta

Land position: 11,545 gross acres, 5,544 net acres
Operator: Purcell

In the third quarter of 2003, Purcell drilled a 40 percent working interest Elkton gas prospect (to earn 50 percent) 40 km northwest of Calgary. The well was completed and flow-tested in December and shut in for pressure build up. Analysis of the pressure data suggests a limited gas pool. Purcell is evaluating the economics of tieing in the well. The Company also intends to review its 3D seismic data to determine whether other opportunities in the area have sufficient potential to be drilled.

Pigeon Lake, Central Alberta

Land position: 4,718 gross acres, 2,162 net acres
Operator: third-party junior

In 2003, Purcell drilled a 50 percent-interest gas discovery at Pigeon Lake. Tie-in of this well was completed in February 2004 and the well is producing at a pipeline-constrained rate of 115 boe/d. In the second quarter of 2004, the Company plans to drill as many as three follow-up wells on the Ellerslie gas play in this area. With further drilling success, Purcell plans to construct a pipeline that will enable the original well to produce at higher rates.

Edson/Pine Creek/Obed, West Central Alberta

Land position: 8,320 gross acres, 3,888 net acres
2003 net production: 0.68 mmcf/d and 9 bbls/d NGLs (123 boe/d)
Operator: various third parties

Purcell is completing and production testing its 50 percent-interest well at Obed in northwest Alberta in the second quarter of 2004. The well was drilled to 3,300 meters and has several gas zones that are being tested and completed. Purcell expects to tie-in the well during the third quarter of 2004. The Company is continuing to acquire additional acreage in the area and expects to drill another well at a 50 percent-interest in the second half of 2004.

Turin, Southeast Alberta

Land position: 6,123 gross acres, 2,701 net acres
2003 net production: 0.62 mmcf/d and 123 bbls/d oil & NGLs (226 boe/d)
Operator: Purcell

Purcell has reviewed all of the seismic data in this area and has also completed reservoir work and determined that there are a number of infill opportunities to be drilled on this acreage. Purcell expects to spud the first of three wells on this all-season access property early in the second quarter 2004.

ahead of the cycle

The following discussion is management's analysis of Purcell Energy Ltd.'s ("Purcell" or the "Company") operating and financial data for 2003 and prior years, as well as estimates of future operating and financial performance based on information currently available. It should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2003, 2002 and 2001. The Management's Discussion and Analysis was prepared as of April 8, 2004. Additional information relating to Purcell, including our Annual Information Form, can be found at www.sedar.com.

Basis of Presentation – The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements – The Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. Purcell's determination of cash flow from operations may not be particularly comparable to that reported by other companies, especially those in other industries. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the audited consolidated financial statements. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

"boe" Presentation – The term barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Forward-Looking Statements

This Management's Discussion and Analysis contains forward-looking information as contemplated by Canadian securities regulators' Form 51-102F1, also known as forward-looking statements. All estimates and statements that describe the Company's objectives, goals or future plans are forward-looking statements. These statements are particularly prevalent in the "Outlook" section.

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by Purcell and described in the forward-looking statements. Actual results could differ materially from those currently anticipated due to any number of factors, including such variables as new information regarding recoverable reserves, changes in demand for, and commodity prices of crude oil and natural gas, legislative, environmental and other regulatory or political changes, competition in areas where the Company operates and other factors outlined in the "Business Risks" section and elsewhere in this Management's Discussion and Analysis. Additional information may also be found in the Company's other reports on file with Canadian securities regulatory authorities.

Forward-looking statements are based on the estimates and opinions of Purcell's management at the time the statements were made. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

2003 Overview

At the beginning of 2003, Purcell's production and assets were still highly concentrated on the Fort Liard natural gas property. Management recognized that it was desirable to diversify the Company's portfolio of properties to reduce this concentration. This was accomplished in large part by the acquisition of BelAIr Energy Corporation in September 2003, which had the effect of reducing Fort Liard to about one-third of total Company reserves at the end of 2003. Also, Fort Liard production fell to about 43 percent of total Company production in the fourth quarter of 2003.

In addition to the diversification provided by the BelAir acquisition, Purcell made significant progress advancing its exploration program, particularly during the second half of 2003. Successful wells were drilled in new areas at West Pembina, Pigeon Lake and Blueberry.

While enjoying strong commodity prices for the year, the industry faced escalating costs for services that forced finding and development costs higher. Also, operating costs rose, in part, due to increasing costs for services. These factors caused depletion and production costs to rise compared to the previous year.

In 2003, Purcell continued its program of reinvestment into exploration projects with a significant focus on high-impact areas in northeast British Columbia and northwest Alberta. The impact of this spending in 2003 and the BelAir acquisition was a

significant increase in undeveloped land holdings, to 329,000 net acres, and an extensive inventory of quality drilling locations. As with all exploration activity, there is inherent risk. Purcell's range of prospects and play-types should diversify the risk and lead to meaningful growth in reserves and production by year-end 2004 and thereafter. Added to the optimism for 2004 is a widely held consensus that natural gas prices will remain strong through the next several years.

Key Facts for 2003:

- 2003 average production of 4,220 boe per day increased by five percent from 2002 production of 4,022 boe per day as a result of the acquisition of BelAir Energy Corporation in September 2003 and successful drilling during the year offset by production declines at Fort Liard and Milo, B.C.
- Production at Fort Liard accounted for 51 percent of Purcell's average production for 2003, down from 65 percent in 2002, reflecting less concentration.
- Reserves at December 31, 2003 were estimated based on the National Instrument 51-101 reserves definitions. Gross proved reserves volumes, based on constant prices and costs, at December 31, 2003 were up 34 percent over the previous year end to 13.8 million boe. Gross proved and probable reserves volumes, based on future prices and costs, were up 40 percent compared to established reserves at the last year end to 18.59 million boe. The prior year end reserves were estimated using the National Policy 2-B reserves definitions.
- 82 percent of Purcell's proved plus probable reserves are natural gas.
- Net revenues increased to $38.8 million in 2003 from $26.7 million in 2002 as a direct result of the acquisition of BelAir and substantially higher natural gas prices received during the year compared to 2002.
- Depletion, depreciation and amortization ("DD&A") expenses increased by 38 percent to $17.1 million in 2003 as a result of the BelAir acquisition and relatively high finding and development costs experienced by Purcell in 2003 and on average over the past three years. On a per boe basis, DD&A climbed in 2003 by 31 percent to $11.08.
- Net income increased by 73 percent to $1.7 million in 2003 reflecting Purcell's larger production base and stronger commodity prices received.
- Cash flow of $21.2 million ($0.618 per share, diluted) was 45 percent (14 percent on a per share basis) higher than 2002.
- Net capital expenditures of $32.7 million, not including the cost of corporate acquisitions, were seven percent lower in 2003 and were funded by cash flow and common share financings.
- Net debt at December 31, 2003 was up 41 percent to $56.8 million as a result of bank debt assumed on the acquisition of BelAir.

Highlights

($ thousands, except per share amounts)	**2003**	2002	2001
Revenues, net of royalties	38,604	26,568	30,253
Cash flow from operations	21,217	14,677	20,717
$ Per share - basic	0.618	0.554	0.821
- diluted	0.618	0.544	0.789
Net income	1,696	982	7,336
$ Per share - basic	0.049	0.037	0.291
- diluted	0.049	0.036	0.279
Capital expenditures, net [1]	32,693	35,232	37,093
Total Assets	209,125	114,914	84,593
Total long-term financial liabilities	4,915	5,000	–
Net Debt [2]	56,794	40,176	21,389

[1] Excludes corporate acquisitions

[2] Includes long-term debt

Acquisition of BelAir Energy Corporation

On September 4, 2003, Purcell completed the acquisition of BelAir for total consideration of $71.3 million. The acquisition was funded through the assumption of net debt of $25.9 million, the payment of cash consideration of $3.2 million, the issuance of 11,343,922 common shares valued at $2.50 per share, the assumption of $5 million of asset retirement obligations and $7.2 million of future income taxes with transaction costs making up the balance. BelAir's consolidated tax pools at the date of the acquisition were approximately $46 million. The operations of BelAir have been included in the consolidated financial statements of Purcell effective from the date of acquisition, September 4, 2003.

BelAir's properties compliment those of Purcell in that both are approximately 80 percent weighted to natural gas. BelAir properties are generally lower risk than Purcell's original properties, with year-round access.

Results of Operations

Production

Average production increased by 5 percent to 4,220 boe/d in 2003 reflecting the production additions from the properties obtained in the acquisition of BelAir in September 2003. Natural gas production gains from successful drilling at Ells/Birch Tar and Fort Liard in the first quarter and other gains during the year were masked by production declines mainly at the Fort Liard M-25 well. The M-25 well is currently shut-in awaiting repairs to the gathering line and facility modifications. The properties acquired in the BelAir acquisition accounted for 15.8 percent and 12.3 percent of the 2003 average crude oil and natural gas production, respectively, representing 13 percent of Purcell's average production for 2003.

Purcell's production in 2003 was weighted 80 percent to natural gas, up slightly from 77 percent for 2002. It is expected that Purcell's production will remain heavily weighted to natural gas in 2004.

The acquisition of BelAir has provided Purcell with greater diversification of its production base and more year-round access allowing for drilling activity to be less seasonal compared to the higher risk/reward winter-access-only mix of properties owned by Purcell prior to the acquisition.

Production

	2003			2002			2001		
	Crude oil & NGLs (bbls/d)	Natural gas (mmcf/d)	boe/d	Crude oil & NGLs (bbls/d)	Natural gas (mmcf/d)	boe/d	Crude oil & NGLs (bbls/d)	Natural gas (mmcf/d)	boe/d
Northwest Territories									
Fort Liard F-25A	-	2.68	446	–	3.29	549	–	2.39	398
K-29	-	5.83	974	–	7.56	1,259	–	8.39	1,398
2K-29	-	2.74	456	–	–	–	–	–	–
M-25	-	1.69	281	–	4.94	823	–	10.69	1,781
Total Northwest Territories	-	12.94	2,157	–	15.79	2,631	–	21.47	3,577
Total British Columbia	1	0.76	127	1	0.05	10	1	0.10	19
Total Alberta	411	6.45	1,486	247	3.72	866	166	2.89	647
Total Saskatchewan	450	-	450	515	–	515	361	-	361
Total Purcell	862	20.15	4,220	763	19.56	4,022	528	24.46	4,604

Revenue

Net revenue of $38.8 million in 2003 was up 45 percent from $26.7 million in 2002 reflecting increased production (up 5 percent) and higher commodity prices (up 43 percent per boe). In the fourth quarter, net revenue increased 66 percent to $12.4 million compared to the same period in 2002 as a result of the full impact of the BelAir acquisition and new production from Purcell's drilling activities. For the year, crude oil production increased by 13 percent to 862 barrels per day, and natural gas production increased to 20.15 mmcf per day. Production declines at Fort Liard were offset by new gas production in other areas. Commodity prices received during 2003 were much stronger for gas, up 57 percent to a wellhead price of $4.81 due to tight North American supplies. Oil prices remained strong in 2003, up eight percent from the previous year.

Revenue Impact ($ thousands)	Crude oil & NGLs	Natural gas	Total
2002 Revenue, before royalties	9,873	20,873	30,746
Increase (decrease) due to:			
Price	357	17,724	18,081
Volume	(494)	(3,746)	(4,240)
Acquisitions	2045	3,757	5,802
2003 Revenue, before royalties	**11,781**	**38,608**	**50,389**
2001 Revenue, before royalties	5,593	26,879	32,472
Increase (decrease) due to:			
Price	1,731	(697)	1,034
Volume	2,321	(5,688)	(3,367)
Acquisitions	228	379	607
2002 Revenue, before royalties	9,873	20,873	30,746

Commodity price strength continued in the fourth quarter of 2003, with natural gas prices up 16 percent to $4.86 per mcf compared to the prior year, although oil and liquids prices slipped three percent to $34.66 per bbl. Fourth quarter production climbed 51 percent to 5,656 boe/d as a result of a full three months contribution of BelAir production, as well as production additions in other areas partially offsetting production constraints at Fort Liard.

Expenses

Increased expenses relate to the higher level of activity in all areas. Costs are increasing throughout the industry in response to high commodity prices and a bullish environment. Purcell's increased activity level has necessitated the addition of technical staff.

Royalty expenses increased in 2003 as a result of crown royalties increasing to an average of $5.05 per boe, an increase of 65 percent over the $3.07 per boe average in 2002. The main reason for this increase was higher prices for natural gas in 2003. In 2002, the Fort Liard royalties increased after reaching pay-out of the project costs. In 2003, royalties for Fort Liard, Alberta and Saskatchewan increased by 52 percent, 15 percent and 10 percent, respectively, substantially as a result of the higher commodity prices. Royalties in Alberta also increased as a result of the BelAir acquisition. Alberta royalty tax credits increased by 99 percent in 2003 and have reached the maximum allowable of $500,000 per year. Royalty expenses increased by 99 percent to $3.98 million in the fourth quarter of 2003 compared to the same period in 2002 mainly for the same reasons mentioned above.

Royalty Expenses (Crown, Freehold and Overrides) by Product

($ thousands)	**2003**	2002	2001
Crude oil and liquids	1,800	1,450	1,059
Natural gas	7,319	3,773	1,434
	9,119	5,223	2,493
Average cost ($/boe)	5.92	3.56	1.48
Percentage of sales revenue	18.0	17.0	6.7

Production expenses per boe increased 32 percent to $7.07 from $5.37 in 2002. The increase relates to generally higher industry costs but also reflects the higher cost remote areas where Purcell is active. Operating costs per boe at Fort Liard increased by nine percent in 2003 due to reduced production volumes. Operating expenses increased further per boe in the fourth quarter of 2003 due to additional production constraints at Fort Liard. As the majority of processing and operating costs at Fort Liard are not variable, the restoration of production levels should result in a reduction of operating costs per unit in 2004. Operating costs per boe in Alberta increased mainly due to production constraints at a third-party facility at Purcell's Rainbow property. Increasing production levels at Rainbow in 2004 are expected to reduce per unit operating costs in this area.

Production expenses

($ thousands)	**2003**		2002		2001	
	Amount	($/boe)	Amount	($/boe)	Amount	($/boe)
Northwest Territories	2,954	3.75	3,292	3.43	3,317	2.54
British Columbia	617	13.30	82	22.14	31	4.50
Alberta	5,382	9.92	2,882	9.11	1,560	6.61
Saskatchewan	1,941	11.82	1,624	8.65	1,485	11.28
Corporate production expenses	10,894	7.07	7,880	5.37	6,393	3.80

General and administrative ("G&A") costs, net, increased by 46 percent to $3.2 million in 2003 due to higher head office costs, in part related to more Company-operated properties after the BelAir purchase. The Company continues to add expertise to manage and exploit its growing asset base. In 2003, Purcell capitalized $1.14 million of G&A expenses related to exploration activities compared to $0.86 million in 2002, reflecting the higher cost levels in 2003. G&A expenses recovered, as part of the process of the Company operating capital projects and producing wells, increased by 12 percent to $559,000 in 2003. It is expected that recoveries will increase with Purcell operating a higher percentage of its properties as a result of the BelAir acquisition. Net G&A expenses in 2004 are expected to be about $4 million.

General and administrative expenses

($ thousands)	**2003**	2002	2001
Personnel costs	2,949	2,130	1,904
Rent and occupancy costs	384	314	237
Other [(1)]	1,579	1,119	1,123
	4,912	3,563	3,264
Capitalized expenses	(1,141)	(867)	(702)
Recoveries	(559)	(501)	(538)
General and administrative costs, net	3,212	2,195	2,024

[(1)] Includes shareholder reporting, insurance, office equipment maintenance, audit and engineering fees.

Depletion, depreciation and amortization ("DD&A") increased by 38 percent in 2003 to $17.1 million representing a 31 percent increase to $11.08 per produced boe. Significantly higher finding and development costs have driven depletion costs upwards in 2003. The Company experienced mixed drilling success in 2003 with net proved reserve additions, after technical revisions, replacing 87 percent of production.

DD&A includes depletion of $0.30 million ($0.34 million in 2002) on the capitalized cost associated with the asset retirement obligation. The retroactive application of the new accounting policy for asset retirement obligations required restatement of prior periods, which resulted in a two percent decrease in the 2002 DD&A to $12.4 million from that previously reported.

Due to the BelAir acquisition, depletion in the fourth quarter of 2003 increased by 41 percent per boe to $12.74 compared to the same period in 2002.

Depletion, depreciation and amortization

($ thousands)	**2003**	2002	2001
Depletion, depreciation and amortization	17,067	12,400	10,092
Average cost ($/boe)	**11.08**	8.45	6.00

Accretion of the asset retirement obligation increased by 52 percent to $0.56 million from $0.37 million recorded in 2002. In 2003, an addition to the asset retirement obligation of $4.96 million was recorded upon the acquisition of BelAir.

Interest expense increased by 95 percent in 2003 to $2.8 million and fourth quarter interest expense of $0.87 million is up 52 percent over 2002 reflecting higher outstanding bank loan balances and the $5 million subordinate debenture financing completed in October 2002. Debt levels were increased in conjunction with the purchase of BelAir and to support the extensive capital program carried out by the Company in 2003.

Income taxes

The Company is not currently taxable except for the federal large corporation tax and provincial capital taxes. In 2003, Purcell recorded a future income tax provision of $1.38 million compared to a $0.93 million provision for 2002. The Company's effective tax rate for 2003 was 38.7 percent compared to 39.0 percent for 2003. Tax pools total approximately $119 million at December 31, 2003 compared to $63 million at December 31, 2002. Included in the tax pools at December 31, 2003 are approximately $20 million of successor costs that are deductible only against income earned from certain petroleum properties. Based on current plans, the Company is not expecting to pay any cash income taxes prior to 2006.

A future tax liability of $7.2 million was recorded upon the acquisition of BelAir as a result of the fair market value for accounting purposes of the assets acquired being in excess of the associated tax basis. The future tax liability was based on the tax rate at the time of acquisition of approximately 39 percent.

Net income and cash flow

Net income increased 73 percent and cash flow from operations increased 45 percent in 2003 as a result of the acquisition of BelAir in September 2003 and 57 percent higher prices received for natural gas. Revenues were up to $38.8 million in 2003 due to a five percent increase in production combined with a 43 percent increase in commodity prices received per boe. Previously expected 2003 income of $5 million and cash flow of $29 million was not achieved as a result of production declines at Fort Liard. Cash flow and revenues in the fourth quarter increased 60 percent and 66 percent, respectively, reflecting 51 percent higher commodity prices received and 10 percent higher equivalent production. The fourth quarter resulted in a net loss of $1.62 million, up from a loss of $0.2 million in 2002, mainly as a result of significantly higher depletion charges and the early adoption of the stock-based compensation rules. The reduction in Fort Liard production is the predominant reason for the decline in net income and cash flow in 2002. In 2004,

additional production at Fort Liard combined with reserves additions and new production in other areas is expected to contribute to a rise in net income to $3 million and an increase in cash flow from operations to $30 million.

Netback Analysis

($/boe)	2003	2002	2001
Revenues	30.77	21.55	19.44
Royalty expenses	5.59	3.39	1.36
Production expenses	7.07	5.37	3.80
Operating netback	18.11	12.79	14.28
General and administrative expenses	2.09	1.49	1.20
Financing charges	1.93	0.98	0.58
Capital taxes	0.32	0.32	0.17
Cash flow from operations	13.77	10.00	12.33
Depletion, depreciation and amortization	11.08	8.45	6.00
Accretion of asset retirement obligation	0.36	0.25	0.14
Stock-based compensation	0.33	–	–
Future income taxes	0.90	0.63	1.82
Net income	1.10	0.67	4.37

Quarterly Summary

	2003				2002			
($thousands, unless otherwise indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Crude oil (bbls/d)	1,102	684	678	690	716	811	642	609
Natural gas liquids (bbls/d)	107	76	56	52	47	72	29	19
Natural gas (mmcf/d)	26.68	19.97	18.24	15.59	17.28	17.11	19.57	24.36
Equivalent (boe/d)	5,656	4,088	3,774	3,340	3,745	3,735	3,933	4,689
Sales prices [1]								
Crude oil ($/bbl)	31.55	38.32	34.34	44.41	35.61	38.72	34.80	29.33
Natural gas liquids ($/bbl)	36.50	37.89	32.54	44.67	35.09	32.14	31.72	19.26
Natural gas ($/mmcf)	4.86	4.58	4.83	5.00	4.19	2.49	3.07	2.65
Revenue, net [1]	13,367	9,025	9,105	8,290	7,465	6,095	6,405	6,712
Net income (loss)	(1,623)	525	1,381	1,413	(201)	594	204	385
$ Per share - basic	(0.034)	0.016	0.049	0.051	(0.008)	0.023	0.008	0.014
- diluted	(0.034)	0.016	0.049	0.050	(0.008)	0.022	0.007	0.014
Cash flow from operations [2]	6,343	4,538	5,253	5,083	3,962	3,132	3,496	4,087
$ Per share - basic	0.132	0.135	0.188	0.183	0.150	0.120	0.131	0.153
- diluted	0.132	0.135	0.187	0.181	0.148	0.118	0.12.8	0.150
Capital expenditures [3]	8,819	5,252	4,824	13,798	6,131	8,651	10,526	9,924

[1] Sales prices and revenue are net of transportation costs.

[2] Please refer to our cautionary non-GAAP advisory regarding cash flow presented at the beginning of the MD&A.

[3] Capital expenditures are net of proceeds from dispositions and exclude costs of corporate acquisitions.

Capital Program

In 2003, Purcell invested $32.7 million, initially budgeted at $27 million, not including the acquisition of Belair. The capital program was funded by the combination of cash flow from operations and the issue of common shares.

Purcell continued to advance its full cycle exploration program in 2003 including the acquisition of additional undeveloped land in Alberta and British Columbia and the participation in drilling of 32 gross (13.44 net) wells. In 2003, depth drilled averaged 4,882 feet (2002 - 5,030 feet) per gross well and 5,150 feet (2002 - 7,000 feet) per net well. This drilled depth is substantially higher than the industry average in the western basin pointing to the deeper, high-risk/high-reward projects targeted by Purcell in 2003 and 2002.

The Company's 2004 capital budget of $32 million is dedicated approximately 66 percent to development drilling, completion and tie-in activities. The Company's plans include drilling 49 gross (25 net) wells in 2004, with moderate-depth wells making up a larger portion than in previous years.

Capital Expenditures

($ million)	**2003**	2002	2001
Undeveloped land	3.0	3.4	4.2
Geological and geophysical	2.8	4.1	6.9
Drilling and completions	20.7	17.3	18.5
Facilities and gathering systems	4.6	10.2	9.0
Acquisitions (dispositions), net	72.2	0.1	(1.7)
Other	0.7	0.1	0.2
Total	104.0	35.2	37.1

Undeveloped Land

	2003		2002		2001	
(acres, at December 31)	**Gross**	**Net**	Gross	Net	Gross	Net
Alberta	526,667	197,586	270,587	81,000	197,660	43,111
Saskatchewan	41,829	19,739	14,839	13,091	32,931	13,896
British Columbia	205,361	111,623	183,326	95,078	113,772	58,744
Northwest Territories	1,600	383	1,596	383	1,596	383
Total	775,457	329,331	470,348	189,552	345,959	116,134

The Company participated in 32 gross (13.44 net) wells, of which 21 (5.59 net) were gas wells, 4 (2.06 net) were oil wells and 7 (5.79 net) were dry, for a success rate of 78 percent (57 percent net). In the fourth quarter, the Company participated in 12 (5.67 net) wells, of which 9 (2.97 net) were gas wells, 2 (1.70 net) were oil wells and 1 (1 net) was dry, for a success rate of 92 percent (82 percent net). Successful wells were drilled at Fort Liard, Ells/Birch Tar and Griffin during the first three quarters of the year and during the fourth quarter at West Pembina, Pigeon Lake, Blueberry, Griffin and Weyburn.

Drilling Activity

	2003		2002		2001	
	Gross	**Net**	Gross	Net	Gross	Net
Exploratory						
Gas	11	2.50	3	0.98	6	1.62
Oil	1	0.17	0	1.00	2	2.00
Dry	6	4.79	5	1.12	–	–
Exploratory Total	18	7.46	9	3.10	8	3.62
Development						
Gas	10	3.09	3	0.28	8	1.85
Oil	3	1.89	3	1.92	3	3.00
Dry	1	1.00	1	1.00	–	–
Development Total	14	5.98	7	3.20	11	4.85
Total	32	13.44	16	6.30	19	8.47

Reserves, Asset Value, Finding and Development Costs

Gilbert Laustsen Jung Associates Ltd. ("GLJ") evaluated substantially all of Purcell's reserves at December 31, 2003, including reserves obtained through the acquisition of BelAir. For several years GLJ evaluated only Purcell's Fort Liard gas reserves. Effective January 1, 2004 GLJ evaluated 92 percent of Purcell's reserves and the balance of the Company's reserves comprising minor properties were evaluated by Purcell's engineers and reviewed by GLJ. The reserves were evaluated in accordance with the new reserves evaluation standards in National Instrument 51-101 using GLJ's April 1, 2004 price forecast. GLJ are qualified and experienced professional engineers and geologists and are independent of Purcell. The reserves evaluators rely on data generally available through public sources supplemented with data provided by Purcell which includes: land interest and lease descriptions, pertinent well data (such as well logs, drill stem tests, workover details, pressure surveys, production tests), geological mapping, property accounting statements, marketing arrangements, and operating and capital budget information.

Purcell's Reserves and Audit Committee oversees the review process by ensuring that the information provided to the evaluators is materially accurate and that the evaluators have not been restricted in any manner. The reserves reports are provided to the Committee for its review and recommendation of approval to the full board.

At January 1, 2004, Purcell's proved reserves increased 34 percent to 13,803 mboe from January 1, 2003 and proved and probable reserves increased by 40 percent to 18,587 mboe compared to established reserves January 1, 2003 determined in accordance with National Policy 2-B. At January 1, 2004, proved reserves and proved and probable reserves were weighted to natural gas 78 percent and 82 percent, respectively. The BelAir acquisition added 3,702 mboe and 5,050 mboe of proved reserves and proved and probable reserves, respectively.

The value of Purcell's proved and probable reserves, discounted at 10 percent per annum, increased to $186.5 million compared to established reserves (proved plus probable reserves risked 50 percent) of $156.8 million at the end of 2002. This year, Fort Liard reserves accounted for 49.3 percent of the value of proved and probable reserves. In comparison, at January 1, 2003, Fort Liard represented 76 percent of the value of the Company's established reserves.

Comprehensive reserves information, including reconciliation tables, for Purcell at January 1, 2004, is available at www.sedar.com in the Company's National Instrument 51-101 disclosure filing.

Reserves replacement

In 2003, Purcell had mixed results from its exploration program, with greater success in the latter part of the year. The successful wells contributed to the addition of 1,339 mboe of proved before-royalties reserves, excluding acquisitions and including a

374 mboe reduction for technical revisions. The proved reserves additions replaced 87 percent of 2003 production. Proved and probable before-royalties reserves additions, not including acquisitions, of 1,786 mboe replaced 116 percent of production. The proved and probable reserves additions in 2003 were calculated in comparison to established reserves at December 31, 2002. In 2002, proved reserves additions and proved and probable reserve additions replaced production by 49 percent and 72 percent respectively.

Finding, development and acquisition costs

Finding and development ("F&D") costs in 2003 included future development costs of $5.3 million for proved reserves and $6.3 million for proved and probable reserves. In addition, 2003 finding and development, net ("F&D, net") costs excluded costs of $9.2 million incurred on undeveloped properties. In 2003, F&D costs remained relatively high reflecting the modest reserves additions and negative technical revisions.

Finding, Development and Acquisition Costs (gross before royalties) [5][6]

($/boe)	**2003**	2002	2001	3-year average	5-year average
Finding & Development (F&D) [1]					
Proved	**29.24**	92.06	17.70	28.26	15.97
Proved and probable [4]	**21.00**	83.48	22.00	27.68	14.12
Finding & Development, net (F&D, net) [2]					
Proved	**26.86**	71.69	13.14	22.86	10.98
Proved and probable [4]	**19.34**	65.12	16.13	22.46	11.71
Finding, Development & Acquisition, net (FD&A, net) [3]					
Proved	**20.09**	36.55	12.84	19.45	12.14
Proved and probable [4]	**14.69**	26.64	16.06	16.38	11.58

(1) F&D costs are calculated by dividing finding and development costs (excluding net acquisition costs) by gross before-royalties reserves additions including revisions but excluding net acquired gross before-royalties reserves.

(2) F&D, net costs are calculated by dividing finding and development costs (excluding net acquisition costs and excluding costs of undeveloped properties) by gross before-royalties reserves additions including revisions but excluding net acquired gross before-royalties reserves.

(3) FD&A, net costs are calculated by dividing finding, development and acquisition costs (excluding costs of undeveloped properties) by gross before royalties reserves additions including revisions.

(4) Proved and probable reserves at December 31, 2002 and prior were estimated using National Policy 2-B reserves definitions and include probable reserves risked at 50 percent.

(5) Finding and development costs include the exploration and development costs incurred during a period adjusted for the change in future development costs associated with the relevant reserves category.

(6) Readers should be aware that the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in the estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Net Asset Value at December 31, before tax

Diluted net asset value, before tax, decreased by 30 percent from the prior year to $3.34 per share at December 31, 2003 as a result of the combined effect of the following factors:

- At December 31, 2002 approximately 76 percent of the Company's established reserves value was attributable to Fort Liard.
- As a consequence of production challenges at Fort Liard, the trading price of Purcell's shares was discounted substantially below the net asset value per share. Purcell issued shares at these discounted levels, which had the effect of diluting net asset value per share.

- Additional capital was invested in Fort Liard without the addition of incremental reserves.
- In conjunction with the BelAir acquisition, the Company completed a $20 million equity financing at a price of $2.45 per share. The financing, although dilutive, was required to ensure a strong balance sheet after the BelAir acquisition.
- Purcell issued 11.3 million common shares at $2.50 per share to shareholders of BelAir as part of the consideration for the purchase of BelAir.
- The Company issued 2,592,400 flow-through shares at $3.00 per share to provide funds for its active 2004 drilling program.

All of the above actions were taken by management to reposition the Company for future growth. The BelAir transaction and related financing broadened Purcell's reserves and production base, and also strengthened the balance sheet.

The reserves value was substantially determined by GLJ with future prices and costs discounted at 10 percent per annum.

Net Asset Value at December 31, before tax

($ million, except as indicated)	***2003***	*2002*
Reserves value, discounted at 10% [1] [2]	186.5	154.5
Undeveloped acreage [4]	22.7	11.5
Seismic data [5]	15.0	9.0
Working capital (deficiency)	(51.9)	(35.2)
Long term debt	(4.9)	(5.0)
Net asset value	167.4	134.80
Net asset value per share		
Basic ($)	3.34	4.88
Diluted ($)	3.34	4.79
Common shares outstanding (thousands)		
Basic	50,090	27,641
Diluted [3]	50,091	28,142

[1] Reserves value at December 31, 2003 is the proved and probable reserves value as prepared using NI 51-101 reserves definitions.

[2] Reserves value at December 31, 2002 is the proved reserves plus probable reserves risked at 50 percent prepared using the National Policy 2-B reserves definitions adjusted for site restoration costs.

[3] The number of diluted outstanding shares is the total of the basic outstanding shares plus the number of additional shares calculated using the treasury method whereby the number of additional shares is the number of shares associated with in-the-money options and warrants at the end of the year reduced by the number of shares that could be repurchased with proceeds received on the exercise of in-the-money options and warrants using the year-end closing price of the shares.

[4] The undeveloped land value at December 31, 2003 is based on a report prepared by the independent consulting firm of Seaton - Jordan & Associates Ltd. dated March 9, 2004.

[5] The seismic data value was estimated by management based on an independent appraisal conducted in December 2002, updated to include seismic data acquisitions in 2003.

Liquidity and Capital Resources

At December 31, 2003, debt, including the working capital deficiency, totaled $56.8 million, up from $40.2 million at December 31, 2002. Year-end debt represents a debt-to-cash flow ratio of 2.7 to one on trailing cash flow and 2.3 to one on annualized fourth quarter 2003 cash flow. Debt is expected to be substantially the same at the end of 2004 and the debt-to-trailing cash flow ratio is expected to improve to between 1.8 and 1.9 to one as a result of increased cash flow from operations in 2004.

Capitalization

($ thousands)	**2003**	2002	2001
Working capital deficiency, excluding bank loan	124	4,473	1,388
Revolving demand bank loan	51,755	30,703	20,000
Subordinate debenture	4,915	5,000	–
Net debt	56,794	40,176	21,388
Asset retirement obligation	10,369	4,721	3,080
Future income taxes	23,644	13,798	10,606
Equity instruments	97,604	42,779	40,301
Retained earnings	3,963	3,889	4,160
Total	192,374	105,363	79,535

Trading and Share Data

	Q4	**Q3**	**Q2**	**Q1**	**2003 Total**	2002 Total
Share trading (thousands) [1]	21,281	25,284	9,085	9,994	65,643	33,188
Share price ($/share)						
High	2.84	2.80	2.89	3.40	3.40	3.60
Low	2.27	2.30	2.27	2.75	2.27	2.01
Close	2.55	2.64	2.40	2.85	2.55	2.91
Market capitalization at December 31 ($ millions)					127,729	80,435
Common shares outstanding (thousands)					50,090	27,641

[1] Purcell's shares trade on the TSX under the symbol PEL.

Debt financing

Management continues to strive to maintain reasonable debt levels. The Company is forecasting that debt levels will reduce from the debt-to-cash flow ratio of 2.7 to one at December 31, 2003 to 1.8 - 1.9 to one by the end of 2004.

Bank credit facility

The Company's revolving demand credit facility was renewed during 2003 with the lending limit increased to $65 million to accommodate the debt assumed on the acquisition of BelAir. Interest is charged at the bank's prime rate plus 1/8 percent per annum. Security for the lending facility is a general security agreement and a hypothecation of a fixed and floating charge demand debenture in the amount of $150 million (2002 - $50 million) supported by oil and gas properties. At December 31, 2003 approximately $52 million of the facility was drawn.

Subordinate debenture

In October 2002, the Company completed a $5 million, 14 percent per annum subordinate debenture financing. It is likely that the Company will exercise its option to payout the debenture in October, 2004 with a penalty payment of six months of interest.

Share capital

The Company is authorized to issue an unlimited number of common shares. At December 31, 2003 there were 50.09 million (December 31, 2002 - 27.64 million) shares outstanding.

During 2003, the Company issued 9,180,000 common shares by way of private placement for gross proceeds of $19.9 million. The Company also issued 653,730 shares on the exercise of stock options for gross proceeds of $0.581 million.

In addition, the Company issued 2,592,400 flow-through shares at $3.00 per share for gross proceeds of $7,777,200. The Company renounced, on December 31, 2003, exploration expenses, for income tax purposes, for the full amount of the equity issue. The Company is committed to spending the funds on qualified expenditures during 2004.

On June 11, 2003 the Company renewed its normal course issuer bid authorizing the Company to purchase for cancellation up to 2.4 million common shares during the period June 13, 2003 to June 12, 2004. During 2003, 1,311,200 common shares were purchased at a cash cost of $3.7 million ($2.79 per share). Of the shares purchased, 337,200 were purchased pursuant to the current issuer bid. The issuer bid was commenced because management considered the purchase of Purcell's shares to be a reasonable investment as the shares were trading, and continue to trade, at a substantial discount to diluted net asset value per share.

Contractual Obligations

The following is a summary of the Company's contractual obligations detailing payments due for each of the next five years and thereafter:

	Expected Payments					
($ thousands)	*2004*	*2005*	*2006*	*2007*	*2008*	*Thereafter*
Revolving demand loan [1]	10,351	10,351	10,351	10,351	10,351	–
Subordinate debenture [2]	85	550	790	3,575	–	–
Office leases [3]	541	484	484	484	484	1,089
Natural gas transportation and treatment [3]	4,248	1,779	1,012	633	–	–
Capital commitments	14,871	–	–	–	–	–
Asset retirement [4]	205	237	2,337	468	4,200	8,120
Total	30,301	13,401	14,974	15,511	15,035	9,209

[1] Based on existing terms of the revolving credit facility whereby if the facility was not renewed it would be converted to a term facility with a term not to exceed five years. However, it is the Company's intention to renew the revolving facility. See note 7 to the consolidated financial statements.

[2] See note 8 to the consolidated financial statements.

[3] See note 14 to the consolidated financial statements.

[4] Calculated using current costs.

Derivative Financial Instruments and Commodity Sales Contracts

Derivative financial instruments and commodity sales contracts may be used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's accounting policy with respect to derivative financial instruments is set out in note 1(q) to the consolidated financial statements.

The Company has entered into commitments to deliver crude oil and natural gas as detailed in note 14(b) to the consolidated financial statements. With the forward contracts, Purcell has hedged approximately 38 percent of its estimated 2004 natural gas production at a minimum sales price of Cdn $5.29 per mcf. In addition, Purcell has hedged approximately 23 percent of its forecast 2004 crude oil production at a minimum sales price of Cdn $35.87 per bbl. The Company has effectively hedged 37 percent of its estimated equivalent production for 2004 at a rate of Cdn $32.41 per boe. This is a relatively comfortable level of delivery commitment that should not present any problems for the Company to fulfill.

The Company has entered into forward foreign exchange contracts to effectively hedge US $6 million or approximately 36 percent of its 2004 United States dollar based revenues. The Company has not hedged foreign exchange risks subsequent beyond 2004.

The Company has not at this time hedged any of its exposure to interest rate changes.

Critical Accounting Estimates

Assumptions, judgements and estimates are often required in the determination of reported amounts for assets, liabilities, revenues and expenses and in the disclosures of contingencies and other financial matters. Management is also often required to adopt accounting policies that require the use of significant estimates. A summary of significant accounting policies adopted by Purcell is contained in note 1 to the consolidated financial statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

Full cost accounting

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. The capitalized costs and future capital costs, net of salvage values, related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Capitalized costs in each cost centre may not exceed the sum of undiscounted future net revenues from proved properties and the cost of unproved properties, net of the provision for impairment, less estimated future financing and administrative expenses and income taxes (the "ceiling test"). If the net capitalized costs of a cost centre are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be charged as an expense against net earnings. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that cost centre.

Oil and natural gas reserves

The Company retains independent petroleum engineering consultants to evaluate the Company's proved and probable oil and natural gas reserves. At the end of 2003, GLJ evaluated 92 percent of the Company's reserves. The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

New Accounting Standards

The Company elected to implement in 2003 early adoption provisions of the under-noted standards that were otherwise to become effective on January 1, 2004. The impact on the financial statements is discussed below.

Asset retirement obligation

The Company early and retroactively adopted the Canadian accounting standard outlined in CICA Handbook section 3110, "Asset Retirement Obligations". This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppels. The initial measurement of the asset retirement obligation is at fair value.

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization. The Company previously estimated costs of dismantlement, removal, site reclamation and other similar activities and recorded them into earnings on a unit-of-production basis over the remaining life of the proved reserves and accumulated a liability on the

Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in a decrease in net income of $120,933 for the year ended December 31, 2003 (2002 - $107,549). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $3,642,910 (2002 - $2,389,302), an increase in liabilities of $4,292,320 (2002 - $2,800,202), and a decrease to opening retained earnings of $410,900 (2002 - $303,351).

Stock-based compensation

The Company early adopted the amendment to the Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". The amendment requires that companies measure all stock based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. As allowed by the section, this policy has been adopted prospectively, meaning prior years have not been restated. The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $510,208 in 2003.

Full cost accounting

The Company early adopted the new CICA Accounting Guideline AcG - 16, "Oil and Gas Accounting – Full Cost". The new guideline modifies how the ceiling test is performed, and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline AcG - 16.

The following new standard was adopted effective January 1, 2004.

Hedging relationships

In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" that deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. The Guideline does not specify how hedge accounting should be applied but does require financial instruments that are not designated as hedges be recorded as fair value on a company's balance sheet, with changes in fair value recorded in income. This guideline was adopted prospectively with no material effect on the financial statements.

Business Risks

Purcell is engaged in exploration and development activity that is subject to the same business risks as any participant in the energy industry. Ownership of common shares should be considered speculative. With a growth strategy that emphasizes exploration for oil and natural gas, Purcell encounters numerous risks that experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered by Purcell at a rate that offsets normal production declines.

Purcell's asset value is based on oil and gas reserves that are independently evaluated or reviewed by Gilbert Laustsen Jung Ltd. (GLJ). This includes reserves obtained through the acquisition of BelAir in 2003. Effective January 1, 2004, GLJ evaluated 92 percent of Purcell's reserves and the balance of the Company's reserves consisting of minor properties were evaluated by Purcell's engineers and reviewed by GLJ. The reserves were evaluated in accordance with the new reserves evaluation standards in National Instrument 51-101 using GLJ's April 1, 2004 price forecast.

The reserves reports represent an estimate of Purcell's interest in its reserves and the future net production revenue derived therefrom. It is important to note that reserves reports include assumptions about the productive capability of each reservoir

and each well into those reservoirs. Being estimates, each well and reservoir could perform differently than estimated, significantly altering the net production revenue ultimately realized.

Commodity price volatility is a significant factor that affects the success of the Company. Purcell is subject to price fluctuations that it has hedged, from time to time, by entering into financial or forward sales contracts. This approach assures a level of capital available for reinvestment but does not ensure that Purcell will necessarily receive the highest possible price available. A significant portion of Purcell's natural gas production generates revenue in United States dollars. Accordingly, these revenues are subject to the foreign exchange risk based on the exchange rate for the US and Canadian dollars.

Capital availability is required for Purcell to realize growth and represents another area of risk. Capital sources used by Purcell include cash flow, bank lines of credit and equity markets. The risks to cash flow levels stem from production sales volumes and prevailing commodity prices. Bank relationships and, in turn, economic conditions, determine the level of credit extended to the Company. Economic conditions and investor confidence influence the availability of equity financing.

Increasing competition in western Canada is adding to the cost of doing business and therefore, increasing the financial risk. Competition also extends to the availability of qualified, professional staff. As for any business, Purcell's continued success is dependent upon its ability to attract and retain experienced management. These areas of competition are not any different than those faced by any other active exploration and development company.

Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. Purcell expects it will be able to fully comply with all regulatory requirements.

The political and economic risks of working in Canada are perhaps as reasonable as anywhere in the world. Canada may suffer economically in conjunction with the economic strain and political uncertainty affecting the US however, this issue is not considered to be significant for the petroleum producing sector in Canada.

Outlook

Purcell entered 2004 with the objective of restoring Fort Liard production levels for the second half of the year and a realistic expectation for adding new production from the drilling activity that has occurred and is extending beyond this winter drilling season.

Production additions over the final three months of 2003 and the first three months of 2004 have been more than offset by production constraints of 1,000 boe/d, primarily at Fort Liard and Milo. First quarter 2004 production was further hampered by unscheduled plant downtime at Fort Liard and temporary interruptions elsewhere from extremely cold winter weather followed by an early spring breakup that reduced volumes by another 400 boe/d. First quarter production was approximately 5,000 boe/d. The effect of these lower production rates is expected to be partially offset by higher oil and natural gas prices for the quarter.

During April of 2004, Purcell's production had already risen to 5,300 to 5,400 boe/d with approximately 300 boe/d behind pipe awaiting tie-in during the second quarter. Total production gains from tie-ins, resolved production constraints and successful Fort Liard drilling (currently ongoing) could amount to 1,800 boe/d by the end of August 2004, moving total Company production to over 7,000 boe/d. Also, production additions could be achieved during the second half of 2004 through drilling success from Purcell's ongoing drilling program that will see wells drilled at Blueberry, Pigeon Lake, Tatagwa, and West Pembina.

Corporate Governance

Overview

The directors and managers of Purcell Energy Ltd. are committed to maintaining high standards of corporate governance. Our corporate governance practices are the responsibility of the Board of Directors and are consistent with the fourteen guidelines for effective governance set out by the Toronto Stock Exchange. All corporations listed on the Toronto Stock Exchange must annually disclose their approach to corporate governance with respect to these fourteen specific guidelines. Our disclosure with respect to each guideline is described in Purcell's management proxy, available on SEDAR at www.sedar.com.

The Board oversees our business strategy, operating strategy and business practices. The Board meets regularly and is consulted with on major issues such as planning, acquisitions and divestitures and its focus is the protection of our assets and shareholder value. The Board has established three standing committees to facilitate the carrying out of the Board's duties and responsibilities and meeting applicable statutory and regulatory requirements. These three committees are the Audit and Reserves Committee, the Compensation Committee, and the Health, Safety and Environment Committee. In addition, from time to time, ad hoc committees may be appointed when special circumstances dictate, with specific assignments for a limited duration.

With respect to corporate governance, the role of the Board is to determine the overall approach to addressing corporate governance issues. The Board monitors, assesses and reviews matters pertaining to the organization and the composition of the Board of Directors, the organization and conduct of Board Meetings, and the effectiveness and independence of the Board, its committees and individual directors. The Board also monitors matters pertaining to standards of business and ethical conduct.

Audit and Reserves Committee

Members of the Audit and Reserves Committee are J. Niedermaier, H. Wheeler and R. Will.

In relation to audit matters, the Audit and Reserves Committee is responsible for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, and financial reporting and statements. They also recommend, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

In relation to reserves matters, the Committee is responsible for reviewing the disclosure procedures of oil and gas activities, reviewing procedures for providing information to the independent evaluator, reviewing the appointment of the independent evaluator, providing a recommendation to the Board as to whether to approve the content and/or filing of the statement of reserves data, reviewing Purcell's procedures for reporting other information associated with oil and gas producing activities; and generally, reviewing all matters relating to the preparation and public disclosure of estimates of Purcell's reserves.

Environment, Health and Safety Committee

Members of the Environment, Health and Safety Committee are B. Murray, J. Niedermaier and H. Wheeler.

The Environment, Health and Safety Committee is an advisory committee that reviews and reports to the Board in all environmental, health and safety matters of the Company. The EHS Committee ensures that the Company has implemented an environmental, health and safety policy that is designed, at a minimum, to comply with current government regulations specific to the operations of the Company.

The Environment, Health and Safety Committee relies on management and independent Environment, Health and Safety consultants to verify compliance with the applicable legal standards and the Company's own policies and to identify compliance issues and areas of weaknesses in the Company's operations.

Compensation Committee

Members of the Compensation Committee are J. Niedermaier, O. Pinnell and R. Will.

The role of the Compensation Committee is to assist the Board of Directors of the Company in fulfilling its responsibility by reviewing matters relating to the human resource policies and compensation of the directors, officers and employees of the Company and its subsidiaries within the context of the budget and business plan of the Company. This includes matters such as compensation philosophy and remuneration policy, Board retainer fees, performance objectives and evaluation of the Chief Executive Officer, compensation and benefit package for senior officers, proposed stock option or share purchase plans, bonuses, and the annual disclosure of compensation information as required by securities law.

Management's Responsibility for Financial Reporting

The accompanying financial statements and all information in the annual report are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies outlined in the notes to the financial statements. Financial statements include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safe-guarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

BDO Dunwoody LLP, the external auditors, conduct an independent examination of the financial statements in accordance with generally accepted auditing standards in order to express their opinion on the financial statements. Their examination includes a review and evaluation of the Company's system of internal control and such tests and procedures considered necessary to provide reasonable assurance that the financial statements are presented fairly.

The audit committee of the Board of Directors, with all of its members being outside directors, have reviewed the financial statements, including notes thereto, with management and BDO Dunwoody LLP. The financial statements have been approved by the Board of Directors on the recommendation of the audit committee.

Jan M. Alston
President and Chief Executive Officer

Terry L. Lindquist
Chief Financial Officer

April 2, 2004

Auditors' Report

To the Shareholders

Purcell Energy Ltd.

We have audited the consolidated balance sheets of Purcell Energy Ltd. as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

BDO Dunwoody LLP

Chartered Accountants
Calgary, Alberta

April 2, 2004

Consolidated Balance Sheets

As at December 31	2003	2002 (Restated Note 2)
Assets		
Current		
Cash	$ 1,711,552	$ 300
Accounts receivable (Notes 4 and 13)	13,547,823	8,309,462
Prepaid expenses and deposits	1,102,271	594,499
Inventory	200,464	435,987
Current portion of loan receivable (Note 5)	188,395	210,880
	16,750,505	9,551,128
Loan receivable (Note 5)	337,213	525,608
Deferred financing costs (Note 8)	642,773	809,552
Deferred pension assets (Note 17)	625,903	387,821
Property, plant and equipment (Note 6)	190,768,313	103,640,202
	$ 209,124,707	$ 114,914,311
Liabilities and Shareholders' Equity		
Current		
Bank indebtedness (Note 7)	$ 51,755,000	$ 30,703,065
Accounts payable and accrued liabilities	16,788,941	13,740,816
Corporate taxes payable	298	283,580
Current portion of subordinate debenture (Note 8)	85,000	–
	68,629,239	44,727,461
Subordinate debenture (Note 8)	4,915,000	5,000,000
Asset retirement obligation (Note 9)	10,369,160	4,721,236
Future income taxes (Note 11)	23,644,369	13,797,643
	107,557,768	68,246,340
Shareholders' Equity		
Equity instruments (Note 10)		
Common shares, net	93,579,749	42,238,862
Share purchase warrants	3,386,363	412,575
Contributed surplus	510,208	–
Preferred shares	128,000	128,000
	97,604,320	42,779,437
Retained earnings	3,962,619	3,888,534
	101,566,939	46,667,971
	$ 209,124,707	$ 114,914,311

Commitments and Contingencies (Notes 14 and 18)

The accompanying notes are an integral part of these consolidated financial statements.

Jan M. Alston, Director

Bruce J. Murray, Director

Consolidated Statements of Operations and Retained Earnings

For the years ended December 31	2003	2002
		Restated (Note 2)
Revenue		
Revenues (Note 12)	$ 38,603,278	$ [illegible]
Interest and other income	183,819	[illegible]
	38,787,097	[illegible]
Expenses		
Production	10,893,675	7,879,760
Depletion, depreciation and amortization	17,066,733	12,399,453
Amortization of deferred financing costs	167,608	17,260
General and administrative, net	3,211,778	2,194,677
Interest	2,809,434	1,441,263
Accretion of asset retirement obligation (Note 9)	560,756	369,866
Stock-based compensation (Note 2 (b))	510,208	-
	35,220,192	24,302,285
Income before corporate taxes	3,566,905	[illegible]
Corporate taxes (Note 11)		
Capital and large corporation taxes	487,628	466,151
Future income taxes	1,383,094	926,060
	1,870,722	1,392,211
Net income for the year	1,696,183	982,062
Retained earnings, beginning of year		
[illegible]	4,299,434	4,463,475
Retroactive adjustment for changes in accounting policies (Note 2)	(410,900)	(303,351)
As restated	3,888,534	[illegible]
Purchase price of common shares repurchased in excess of book value (Note 10)	(1,622,098)	(1,253,652)
Retained earnings, end of year	$ [illegible]	$ [illegible]
Earnings per common share - basic	$ 0.049	$ [illegible]
- diluted	$ 0.049	$ [illegible]

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31	2003	2002 (Restated Note 2)
Cash flows from operating activities		
Net income for the year	$ 1,696,183	$ 982,062
Adjust for non-cash items:		
Depletion, depreciation and amortization	17,066,733	12,399,453
Accretion of asset retirement obligation (Note 9)	560,756	369,866
Stock-based compensation	510,208	–
Future income taxes	1,383,094	926,060
Cash flow from operations	21,216,974	14,677,441
Net change in non-cash working capital balances (Note 16)	(1,855,989)	2,831,922
	19,360,985	17,509,363
Cash flows from financing activities		
Payments from (to) Liard Resources Ltd.	419,976	(407,768)
Decrease (increase) in deferred financing costs	166,779	(396,977)
Increase in debenture	–	5,000,000
Issue of common shares, net of related expenses	26,410,677	6,091,578
Repurchase of common shares	(3,683,436)	(3,013,588)
Issue of warrants, net of related expenses	2,914,125	–
Repayment of capital leases	–	(5,462)
Increase (decrease) in utilization of bank credit facilities	(1,906,565)	10,702,581
	24,321,556	17,970,364
Cash flows from investing activities		
Net change in non-cash working capital balances (Note 16)	(3,082,805)	488,979
Decrease (increase) in loan receivable	210,880	(736,488)
Purchase of BelAir Energy Corporation (net of cash acquired)	(6,382,769)	–
Site restoration costs incurred	(43,435)	–
Purchases of property, plant and equipment	(32,701,889)	(38,357,216)
Proceeds on disposition of property, plant and equipment	28,729	3,124,735
	(41,971,289)	(35,479,990)
Increase (decrease) in cash	1,711,252	(263)
Cash, beginning of year	300	563
Cash, end of year	$ 1,711,552	$ 300

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Significant Accounting Policies

The Company was incorporated on December 5, 1986 pursuant to the Alberta Business Corporation Act. Since inception, the Company's efforts have been devoted to the acquisition, exploration and development of oil and gas properties in western Canada.

The consolidated financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. The preparation of consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgement with reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Principles of consolidation

The consolidated financial statements include the accounts of Purcell Energy Ltd. (the "Company") and its wholly-owned subsidiaries 421416 Alberta Ltd., 641294 Alberta Ltd., 757382 Alberta Ltd., BelAir Exploration Inc. and Cirque Energy (UK) Limited and the Company's proportionate interest in the accounts of Northcor Exploration Fund 1988 and Western Exploration Fund 1988. Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts. Investments in companies and partnerships in which the Company does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

(b) Revenue recognition

Revenues associated with the sales of the petroleum products produced by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Revenues are reported net of transportation costs.

(c) Inventories

Inventories of petroleum products, operating supplies and raw materials are valued at the lower of cost and net realizable value.

(d) Property, plant and equipment

The Company accounts for crude oil and natural gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs associated with the acquisition of, exploration for and the development of, natural gas and crude oil reserves, including asset retirement costs, are capitalized.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated gross (before deducting royalties) proved reserves. For purposes of this calculation, gas is converted to oil on an energy equivalent basis. Capitalized costs subject to depletion are net of equipment salvage values and include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment

loss is limited to the amount by which the carrying amount exceeds the sum of: (a) the fair value of proved and probable reserves; and (b) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Other property and equipment are recorded at cost. Depreciation is provided using the straight-line method based over the estimated useful lives at rates of 10 percent to 35 percent per annum.

Expenditures that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are charged against income.

(e) Joint venture operations

The majority of the Company's petroleum and natural gas exploration activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(f) Asset retirement obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines, and management's estimate on a site-by-site basis. The liability is subsequently adjusted for the passage of time, and is recognized as an accretion expense in the statement of operations under asset retirement obligations. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. The increase in the carrying value of the asset is amortized using the unit of production method based on estimated gross proven reserves as determined by independent engineers. Actual expenditures incurred are charged against the accumulated obligation.

(g) Marketable securities

Marketable securities are carried at the lower of cost and market.

(h) Flow-through equity instruments

Expenditure deductions for income tax purposes related to exploratory activities funded by flow-through share/warrants arrangements are renounced to investors in accordance with income tax legislation. The Company provides for the future effect on income taxes related to flow-through shares as a charge to share capital when the expenditures are incurred. No liability regarding future taxes is recorded on unexpended flow-through share capital.

(i) Financial instruments

The Company carries a number of financial instruments. It is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of these financial instruments approximate their carrying values, unless otherwise noted.

(j) Cash and cash equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

(k) Measurement uncertainty

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material. The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

The financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements the accruals made by management in this regard may be significantly different from those determined by the Company's joint venture partners. The effect on the financial statements resulting from such adjustments, if any, will be reflected prospectively.

(l) Future income taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs.

(m) Stock based benefit plan

The Company records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period (see Note 2).

(n) Employee benefit plans

The cost of employee pensions and other retirement benefits is actuarially determined using the aggregate actuarial cost method based on actuarial liability for projected benefits earned in respect of all service to the plan members' assumed retirement date. The expected return on plan assets is based on the fair value of those assets. The excess of any net actuarial gain or loss exceeding 10 percent of the greater of the benefit obligation and the fair value of plan assets is amortized over estimated average remaining service period of the remaining active employees.

(o) Earnings per share amounts

Basic earnings per common share is computed by dividing earnings by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments.

(p) Prepaid expenses and deposits

Prepaid expenses and deposits include payments for insurance premiums and lease rentals that relate to future periods, and deposits paid to various government agencies and other companies for future crown royalties, well and facility operating costs and office lease payments.

(q) Derivative financial instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions. Gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related production occurs.

The Company may utilize derivative financial instruments such as interest rate swap agreements to manage the interest rate mix of the Company's debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may also purchase foreign exchange forward contracts to hedge anticipated sales denominated in United States dollars and the related accounts receivable. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

(r) Deferred financing costs

Deferred financing costs relate to the subordinate debenture. These costs include the costs incurred to complete the debenture financing and also include the fair value of the transferable warrants issued. These costs are being amortized over the five year term of the debenture agreement.

(s) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2003.

2. Changes in Accounting Policies and Practices

There have been several changes in the financial reporting and securities regulatory environment in 2003 that have impacted all public companies. The Company elected to implement early adoption provisions of the standards.

(a) Asset retirement obligation

The Company has retroactively early adopted the Canadian accounting standard outlined in CICA Handbook section 3110, "Asset Retirement Obligations". This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppels. The initial measurement of the asset retirement obligation is at fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization. The Company previously estimated costs of dismantlement, removal, site reclamation and other similar activities and recorded them into earnings on a unit-of-production basis over the remaining life of the proved reserves and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in a decrease in net income of $120,933 for the year ended December 31, 2003 (2002 - $107,549). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $3,642,910 (2002 - $2,389,302), an increase in liabilities of $4,292,320 (2002 - $2,800,202), and a decrease to opening retained earnings of $410,900 (2002 - $303,351).

(b) Stock-based compensation

The Company has early adopted the Canadian accounting standard as outlined in CICA Handbook section 3870, "Stock-based Compensation and Other Stock-based Payments". As allowed by the section, this policy has been adopted prospectively, meaning all prior years have not been restated. The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $510,208 in 2003.

(c) Full cost accounting

The Company has early adopted the new CICA Accounting Guideline AcG - 16, "Oil and Gas Accounting – Full Cost". The new guideline modifies how the ceiling test is performed, and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of

a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows (see Note 1). Additional disclosures are also required as provided in Note 6. There is no impact on the Company's reported financial results as a result of applying the new Accounting Guideline AcG - 16.

3. Business Acquisition

On September 4, 2003, the Company purchased, pursuant to a Plan of Arrangement, all of the issued and outstanding shares of BelAir Energy Corporation ("BelAir"). The acquisition was accounted for using the purchase method with the results of operations of BelAir being included from the date of acquisition. The purchase price was allocated as follows:

Property, plant and equipment	$	71,347,540
Current assets (including cash of $659,598)		5,155,483
Current payables		(8,063,087)
Bank indebtedness		(22,958,500)
Asset retirement obligation		(4,956,458)
Future income taxes		(7,155,038)
Net assets acquired	$	33,369,940
Purchase price attributed to:		
11,343,922 common shares issued	$	28,359,805
Cash consideration paid		3,204,498
Costs of the transaction paid in cash		1,805,637
	$	33,369,940

4. Share Purchase Loans

Included in accounts receivable are loans of $187,500 (2002 - $182,500) due from directors and employees of the Company who are key members of the Company's management team. These loans were made for market purchases of stock of the Company. The loans are unsecured, bear interest at prime and are due on demand.

5. Loan Receivable

On April 1, 2002 the Company sold 7.96 percent of its capacity rights in the Fort Liard pipeline to a Fort Liard-based third party for $1,850,000. Pursuant to the sale agreement, the Company provided $850,000 of financial assistance to the purchaser in the form of a loan receivable. The agreement calls for monthly payments of principal plus interest at an effective rate of 7.6 percent per annum and is due no later than March 1, 2007. Principal payments are currently scheduled as follows:

2004	$	188,395
2005		199,952
2006		137,261

6. Property, Plant and Equipment

2003	Cost	Accumulated depletion, depreciation and amortization	Net book value
Petroleum and natural gas properties and equipment	$ 247,575,975	$ 57,755,782	$ 189,820,193
Other assets	1,616,461	668,341	968,120
	249,192,436	58,424,123	190,768,313
2002			
Petroleum and natural gas properties and equipment	$ 144,371,073	$ 40,965,607	$ 103,405,466
Other assets	710,588	475,852	234,736
	145,081,661	41,441,459	103,640,202

As at December 31, 2003, costs of acquiring unproved properties in the amount of $26,434,000 (2002 - $19,979,000) and facilities and equipment salvage values of $10,567,000 (2002 - $Nil) were excluded from depletable costs. During the year, approximately $1,141,000 (2002 - $868,000) of general and administrative costs were capitalized to oil and gas properties.

An impairment assessment was made on the Company's property, plant and equipment at December 31, 2003 in which the estimated undiscounted future net cash flows associated with proved reserves exceeded the carrying amount of the Company's property, plant and equipment. A similar test performed at January 1, 2003 upon adoption of AcG - 16 also resulted in a surplus.

The following table outlines benchmark prices used in the impairment test at December 31, 2003:

Year	WTI Crude Oil US$/bbl	Exchange Rate US$/Cdn$	Edm Light Crude Cdn$/bbl	AECO Natural Gas Cdn$/Mcf
2004	34.25	0.75	44.75	6.65
2005	29.00	0.75	37.75	5.55
2006	27.00	0.75	35.25	5.20
2007	25.00	0.75	32.50	5.00
2008	25.00	0.75	32.50	5.00
Thereafter (inflation %)	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr

7. Bank Indebtedness

	2003	2002
Bank operating loan	$ 51,755,000	$ 28,865,000
Bank overdraft	-	1,838,065
	$ 51,755,000	$ 30,703,065

During the year, the Company secured a new revolving demand credit facility of $65 million (2002 - $35 million) with a Canadian chartered bank. Interest is charged at the bank's prime rate plus 1/8 percent per annum on the bank-operating loan. The facility is supported by a general security agreement and a hypothecation of a fixed and floating charge demand debenture in the amount of $150 million (2002 - $50 million) supported by oil and gas properties. The facility will be reviewed prior to May 31, 2004 and if not renewed, shall be converted to a term facility with a term not exceeding 5 years.

8. Subordinate Debenture

On October 18, 2002 the Company completed a $5 million debenture financing. The debenture is subordinate to the Company's bank revolving credit facility, has a term of five years and bears interest at 14 percent per annum payable monthly. No principal is payable during the first 2 years of the term. Purcell has the right to prepay the entire outstanding principal anytime after October 17, 2004 with payment of six months interest. The debenture holder has been issued a transferable warrant entitling the warrant holder to purchase, on or before October 18, 2007, 625,000 common shares of the Company at $3.25 per share. Costs incurred to complete the debenture financing have been recorded as deferred financing costs. These costs are being amortized to expense over the term of the debenture. Principal payments are due as follows:

2004	$ 85,000
2005	550,000
2006	790,000
2007	3,575,000

9. Asset Retirement Obligation

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties.

As at December 31	2003	2002
Asset retirement obligation, beginning of year	$ 4,721,236	$ 3,080,241
Liabilities assumed on corporate acquisition	4,956,458	–
Liabilities incurred	174,145	1,271,129
Liabilities settled	(43,435)	–
Accretion expense	560,756	369,866
Asset retirement obligation, end of year	$ 10,369,160	$ 4,721,236

The undiscounted amount of cash flows, required over the estimated reserve life of the underlying assets, to settle the obligation, adjusted for inflation, is estimated at $20,196,437 (2002 - $10,576,340). The obligation was calculated using a credit-adjusted risk free discount rate of 8.5 percent and an inflation rate of 2 percent. It is expected that this obligation will be funded from general Company resources at the time the costs are incurred with the majority of costs expected to occur between 2007 and 2033. No funds have been set aside to settle this obligation.

10. Equity Instruments

Authorized

The authorized share capital of the Company consists of an unlimited number of:

Common voting shares;

Preferred non-voting shares issuable in series, rights to be determined on issue; and

Series I convertible preferred shares.

The common shares are entitled to dividends in such amounts as the directors may from time to time declare and, in the event of liquidation, dissolution or winding-up of the Company, are entitled to share pro rata in the assets of the Company.

The preferred shares rank in priority to the common shares as to the payment of dividends and as to the distribution of assets in the event of liquidation, dissolution or winding-up of the Company. Preferred shares may also be given such other preferences over the common shares as may be determined for any series authorized to be issued.

Issued

Common shares	**December 31, 2003**		December 31, 2002	
	Number of Shares	Amounts	Number of Shares	Amounts
Balance, beginning of period	27,641,039	$ 42,238,862	26,512,840	$ 40,172,852
Issued for cash				
By private placement	1,000,000	2,900,000	–	–
By private placement	8,180,000	16,973,500	–	–
By private placement of flow through shares	2,592,400	7,777,200	2,071,399	6,214,197
By exercise of BelAir stock options	11,730	30,000	–	–
By exercise of Purcell stock options	642,000	551,150	287,000	280,500
Issued to acquire BelAir Energy Corporation (note 3)	11,343,922	28,359,805	–	–
Repurchased for cancellation	(1,321,200)	(2,061,338)	(1,230,200)	(1,759,936)
Share issue costs, net of future tax effect		(1,175,608)		(245,275)
Future tax effect on renunciation of exploration expenses		(2,013,822)		(2,423,476)
Balance, end of period	50,089,891	$ 93,579,749	27,641,039	$ 42,238,862

Number of shares outstanding	**December 31, 2003**		December 31, 2002	
	End of period	Weighted Average	End of Period	Weighted Average
Common shares – basic	50,089,891	34,329,535	27,641,039	26,491,049
Options to purchase common shares	3,313,700	1,244	2,912,700	481,652
Warrants to purchase common shares	8,805,000	-	625,000	–
Common shares – diluted	62,208,591	34,330,779	31,178,739	26,972,701

During March 2003, the Company completed a private placement financing for an aggregate of 1,000,000 common shares at a price of $2.90 per share for gross proceeds of $2,900,000.

In connection with the acquisition of BelAir Energy Corporation, the Company closed, on July 24, 2003, a financing by way of private placement. The Company issued 8,180,000 subscription receipts at $2.45 per subscription receipt for gross proceeds of $20,041,000. After obtaining shareholder approval for the financing at a special meeting of shareholders, the Company, on September 4, 2003, exchanged each subscription receipt for one common share and one common share purchase warrant of the Company.

During December 2003, the Company completed a private placement financing for an aggregate of 2,592,400 flow-through shares at a price of $3.00 per share for gross proceeds of $7,777,200. The Company is committed to spending $7,777,200 on qualified expenditures by December 31, 2004. As of December 31, 2003, the Company had expended $Nil on qualified expenditures related to the December 2003 financing.

During 2003 the Company repurchased 1,321,200 of its common shares at a purchase cost of $3,683,436 resulting in a $1,622,098 reduction in retained earnings.

During December 2002, the Company completed private placements for an aggregate of 2,071,399 flow-through shares at a price of $3.00 per share for gross proceeds of $6,214,197. One senior officer of the Company purchased 2,000 of the flow through shares.

During 2002 the Company repurchased 1,230,200 of its common shares at a purchase cost of $3,013,588 resulting in a $1,253,652 reduction in retained earnings.

Share purchase warrants	***December 31, 2003***		*December 31, 2002*	
	Number of Shares	Amounts	Number of Shares	Amounts
Balance, beginning of period	625,000	$ 412,575	–	$ –
Issued during the period	8,180,000	3,067,500	625,000	412,575
Issue costs	–	(153,375)	–	–
Future taxes on issue costs	–	59,663	–	–
Balance, end of period	8,805,000	$ 3,386,363	625,000	$ 412,575

On September 5, 2003, the Company issued 8,180,000 warrants pursuant to the private placement of subscription receipts that closed on July 23, 2003. The warrant entitles the holder to acquire one common share of Purcell at an exercise price of $5.00 expiring July 23, 2008. The fair value of the warrants was estimated at $3,067,500 using the Black Scholes option-pricing model with the following assumptions: Dividend yield (Nil); expected volatility (0.34); risk-free interest rate (5.0%); and weighted average life of five years.

At December 31, 2002, there were 625,000 warrants outstanding. Each warrant entitles the holder to purchase one common share at $3.25 per share on or before October 18, 2007.

Preferred shares	***2003***		*2002*	
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	2,276	$ 128,000	2,276	$ 128,000
Balance, end of year	2,276	$ 128,000	2,276	$ 128,000

The preferred shares earn cumulative dividends at 5 percent and were convertible into 76,815 Common shares on or before December 31, 1997 at the option of the holder. No preferred shares were converted prior to December 31, 1997 so the conversion privilege has expired. The preferred shares are redeemable at $56.25 per share. Preferred shares dividends in arrears as at December 31, 2003 amounted to $54,165 (2002 - $47,565).

Options

The Company has a stock option plan under which employees, directors and consultants are eligible to receive grants. On December 31, 2003 4,000,000 (2002 - 4,000,000) common shares were reserved for issuance under the plan. Options granted under the plan generally have a term of five years to expiry. Initial grants of options generally vest one-third immediately with the balance vesting in equal amounts on the first and second anniversary of the date of the grant. Subsequent grants generally vest equally over a three-year period starting on the first anniversary date of the grant. The exercise price of each option equals or exceeds the market price of the Company's common shares on the date of the grant. At December 31, 2003, 3,313,700 options with exercise prices between $2.15 and $3.75 were outstanding and exercisable at various dates to the year 2008.

Options	2003		2002	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Stock options, beginning of period	2,912,700	$ 2.45	2,702,700	$ 2.31
Granted	1,123,000	2.64	637,000	2.57
Exercised	(642,000)	0.86	(287,000)	0.98
Forfeited	(80,000)	0.90	(140,000)	3.39
Stock options outstanding, end of period	3,313,700	$ 2.81	2,912,700	$ 2.45
Exercisable, end of period	1,945,699	$ 2.92	1,914,532	$ 2.25

	Options outstanding			Options exercisable	
Range of exercise prices	Options outstanding	Weighted average remaining term (years)	Weighted average exercise price	Options exercisable	Weighted average exercise price
$2.00 - $2.99	2,332,700	3.4	$ 2.52	1,102,365	$ 2.65
$3.00 and over	981,000	2.4	2.62	843,334	3.28
	3,313,700	3.1	$ 2.81	1,945,669	$ 2.92

As described in Note 2, the Company recorded stock-based compensation expense in the Consolidated Statement of Operations for stock options granted to employees and directors in 2003 using the fair-value method. Compensation expense has not been recorded related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, net income and net earnings per common share would have been reduced to the pro forma amounts indicated below:

	2003	2002
Net income		
As reported	$ 1,696,183	$ 982,062
Pro forma	$ 1,213,650	$ 7,350
Basic earnings per share		
As reported	$ 0.049	$ 0.037
Pro forma	$ 0.035	$ 0.036
Diluted earnings per share		
As reported	$ 0.049	$ 0.000
Pro forma	$ 0.035	$ 0.000

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	2003	2002
Weighted average fair value of options granted	$ 1.49	$ 1.47
Risk-free interest rate	4.00%	4.61%
Expected lives (years)	5	5
Expected volatility	0.63	0.64
Annual dividend per share	$ –	$ –

11. Corporate Taxes

The effective rate of income tax varies from the statutory rate as follows:

	2003	2002
Combined tax rate	39.12%	39.12%
Expected income tax provision at statutory rate	$ 1,395,373	$ 928,816
Differences due to resource deductions	137,513	779,954
Net effect of rate reduction	-	(750,500)
Other differences	(149,792)	(32,210)
Provision for large corporations and provincial capital taxes	487,628	466,151
Actual income tax provision	$ 1,870,722	$ 1,392,211

Subject to confirmation by income tax authorities, the Company has the following approximate undeducted tax pools:

	2003	2002
Cumulative Canadian Oil and Gas Property Expenses *	$ 25,735,169	$ 10,628,448
Cumulative Canadian Development Expenses *	$ 14,744,328	$ 7,311,935
Cumulative Canadian Exploration Expenses *	$ 9,337,754	$ 15,571,981
Undepreciated Capital cost	$ 58,515,279	$ 27,460,167
Non-capital losses carried forward for tax purposes available from time to time until 2006	$ 8,496,049	$ 1,793,327
Share issue costs	$ 2,788,135	$ 883,059
Net capital losses carried forward	$ 94,734	$ 94,734

These pools are deductible from future income at rates prescribed by the Canadian Income Tax Act.

* Certain tax pools acquired are successored and can only be used against income generated from certain properties.

The components of the Company's future income tax liabilities are a result of the origination and reversal of temporary differences and are comprised of the following:

	2003	2002
Capital assets	$ 28,033,917	$ 14,844,646
Share issue costs	(1,084,585)	(345,453)
Unused tax losses carryforward	(3,304,963)	(701,550)
Future income tax liability	$ 23,644,369	$ 13,797,643

12. Revenues

Revenues include the following:

	2003	2002
Petroleum and natural gas sales	$ 50,388,903	$ 30,745,613
Commodity hedge gain (loss)	(3,235,387)	751,980
Royalty revenue	67,137	41,748
Crown royalty expense	(7,776,175)	(4,510,419)
Freehold and overriding royalty expense	(1,342,666)	(712,272)
Alberta royalty tax credit	501,466	251,466
	$ 38,603,278	$ 26,568,116

13. Related Party Transactions

During the year ended December 31, 2003, the Company:

(a) charged $30,024 of interest to Liard Resources Ltd. ("Liard")

(b) received net loan payments of $419,976 from Liard; and

(c) charged $8,699 of interest on loans to employees and directors as detailed in Note 4.

During the year ended December 31, 2002, the Company:

(d) charged $27,768 of interest to Liard Resources Ltd. ("Liard")

(e) paid net loan payments of $407,768 to Liard; and

(f) charged $7,658 of interest on loans to employees and directors as detailed in Note 4.

Liard is a shareholder of the Company and is related by virtue of having common management. Included in accounts receivable is an amount due from Liard of $254,193 (2002 - $674,169). The balance earned interest at prime plus 1 percent per annum. Subsequent to the year end, Liard repaid the full amount of the loan plus accrued interest.

These transactions were measured at the exchange amount which is the amount of consideration established and agreed to by the related parties.

14. Commitments

(a) Office lease

The Company is committed to three lease agreements for office space expiring October 31, 2004, November 30, 2004 and March 31, 2011. In addition to operating costs, the lease agreements require annual minimum lease payments as follows:

2004	$	541,143
2005 - 2011		484,037

(b) Commodities

The Company has entered into contracts to hedge commodity prices (financial) and deliver petroleum and natural gas (physical). The terms of the contracts are summarized as follows:

Contract Type	Product	Floor/Strike Price	Ceiling Price	Volume	Contract Term
Physical	Natural Gas	$6.50 per GJ at AECO	$8.50 per GJ	7,000 GJ per day	Nov 1, 2003 to Apr 1, 2004
Physical	Natural Gas	$5.70 per GJ at AECO		4,000 GJ per day	Nov 1, 2003 to Oct 31, 2004
Physical	Natural Gas	$5.20 per GJ at AECO		5,000 GJ per day	Apr 1, 2004 to Oct 31, 2004
Physical	Natural Gas	$4.70 per GJ at AECO	$5.70 per GJ	2,500 GJ per day	Apr 1, 2004 to Mar 31, 2005
Physical	Natural Gas	$5.50 per GJ at AECO	$7.425 per GJ	5,000 GJ per day	Nov 1, 2004 to Mar 31, 2005
Physical	Crude Oil	$25.15 per bbl WTI		100 bbls per day	May 1, 2003 to Apr 30, 2004
Physical	Crude Oil	$28.63 per bbl WTI		300 bbls per day	Nov 1, 2003 to Nov 1, 2004

If the contracts were terminated at December 31, 2003, the Company would have to pay $1,347,000 (December 31, 2002 - $2,612,000).

(c) Foreign exchange

The Company has entered into a collar arrangement to hedge future commodity revenue received in United States dollars. The arrangement covers US $500,000 per month during 2004 with an exchange rate floor of Cdn $1.29 per US $1 and an average ceiling of Cdn $1.34 per US $1.

If this arrangement was terminated at December 31, 2003, the Company would receive $42,000.

(d) Employment contracts

The Company has employment agreements in place where certain members of the management team will receive between 6 months to 2 years remuneration for severance upon termination without cause and/or change of control of the Company. The current total commitment on termination is estimated to be approximately $1,540,400.

(d) Transportation and processing

The Company has contracted to secure firm service for the transportation and processing of natural gas produced from several Company-owned properties. The agreements call for the following payments to be made by the Company:

2004	$ 4,248,000
2005	1,779,000
2006	1,012,000
2007	633,000

15. Financial Instruments

As disclosed in Note 1(i), the Company holds various forms of financial instruments. The nature of these instruments and the Company's operations expose the Company to interest rate, commodity price and industry credit risks. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

(a) Interest rate risk management

The Company's short and long-term borrowings are subject to floating rates. The floating rate debt is subject to interest rate cash flow risk, as the required cash flows to service the debt will fluctuate as a result of changes in market rates.

As at December 31, 2003, the increase or decrease in net earnings before taxes for each 1 percent change in interest rates on floating rate debt amounts to approximately $518,000 (2002 - $307,000) per annum. The related disclosure regarding these debt instruments is included in Note 7 of these financial statements.

(b) Commodity price risk

The Company is subject to commodity price risk for the delivery of natural gas and crude oil under the contracts detailed in Note 14(b). The Company managed the risk by delivering natural gas and crude oil received in kind on behalf of the Company and several sub-participants from the operations of various joint ventures. The sub-participants are not involved in the contracts; however, the Company pays the sub-participants for their share of gas/oil sold at the prices received by the Company. The obligations to deliver under the contracts are the sole responsibility of the Company.

(c) Credit risk

A significant portion of the Company's trade accounts receivable are from working interest partners in the oil and gas industry and, as such, the Company is exposed to all the risks associated with that industry.

16. Supplemental Disclosure of Cash Flow Information

(a) Net change in non-cash working capital:

Operating activities	2003	2002
Accounts receivable	$ 1,181,931	$ (2,776,540)
Prepaid expenses and deposits	140,510	(159,073)
Inventory	304,782	(294,301)
Deferred pension asset	(238,082)	(387,821)
Accounts payable and accrued liabilities	(2,961,848)	6,166,172
Corporate taxes payable	(283,282)	283,485
	$ (1,855,989)	$ 2,831,922

Investing activities	2003	2002
Accounts receivable	$ (3,061,923)	$ (646,043)
Accounts payable and accrued liabilities	(20,882)	1,135,022
	$ (3,082,805)	$ 488,979

(b) Additional information:

Interest and taxes paid

	2003	2002
Interest paid	$ 2,764,065	$ 1,438,571
Corporate taxes paid	$ 770,910	$ 182,666

17. Employee Benefits

Effective July 1, 2001 the Company initiated a strategy for the long-term retention of senior executives by the establishment of a Retirement Compensation Arrangement (RCA) plan governed by a trust agreement. The Company funds the RCA fully with payments that are based on actuarial calculations. The approximate amount of the future annual benefits is covered by insurance contracts. Upon reaching the normal retirement age of 60, a fixed benefit amount is payable monthly to or on behalf of a named executive over a 25-year period. Annual benefits are reduced in the event of retirement before the normal retirement age. No benefit is payable if service is terminated by a plan member before July 1, 2006. If the Corporation terminates, for any reason other than death, disability or cause, the employment of a plan member, the retirement benefit amount payable is calculated as a percentage of the normal retirement benefit. The percentage utilized is 20 percent if termination occurs prior to July 1, 2004 and increases in annual increments of 10 percent until the full amount of the normal retirement benefit is payable. In the event of a change in control (as defined in the RCA plan) of the Company and within three months thereafter the Company terminates the employment of a named executive or a named executive voluntarily terminates his or her employment with the Corporation, the retirement benefit under the RCA Plan is calculated at 60 percent of the normal retirement benefit if termination occurs prior to July 1, 2004 and increases in annual increments thereafter of 10 percent until the full amount of the normal retirement benefit is payable.

Information about the Company's defined benefit plans, in aggregate, is as follows:

Pension benefit plans

	2003	2002
Plan assets		
Fair value, at beginning of year	$ 434,952	$ 140,400
Actual return on plan assets, including mortality cost portion of insurance premiums	(37,692)	(106,348)
Employer contributions	400,900	400,900
Fair value, at end of year	798,160	434,952
Accrued benefit obligation		
Balance, at beginning of year	213,039	74,700
Current service costs	144,657	142,026
Interest cost	21,462	13,004
Actuarial (gains) losses	(17,515)	16,691
Balance, at end of year	361,643	213,039
Funded status – plan surplus	436,517	221,913
Unamortized actuarial loss	189,386	165,908
Accrued benefit asset, at end of year	$ 625,903	$ 387,281

The significant actuarial assumptions adopted in measuring the Company's accrued benefit obligation are as follows:

	2003	2002
Discount rate	6.0%	6.0%
Expected long-term rate of return on plan assets	6.0%	6.0%
Rate of compensation increase	0.0%	0.0%

The Company's net benefit plan expense is as follows

	2003	2002
Current service cost	$ 144,657	$ 142,026
Interest cost	21,462	13,004
Expected return on plan assets	(12,717)	(8,072)
Amortization of net accrual loss	9,416	4,512
	$ 162,818	$ 151,470

18. Contingencies

The Company is subject to various regulatory and statutory requirements relating to the protection of the environment. The Company has recognized a liability at December 31, 2003 of $10,369,160 related to the retirement of its long-lived petroleum assets based on current legislation and estimated costs. Any changes in these estimates will affect future earnings.

The operations of the Company are complex, and related tax interpretations, regulations and legislation affecting the Company are continually changing. As a result, there are usually some tax matters under review. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year.

Five Year Summary

Years ended December 31 ($000, except where indicated, 6 mcf = 1 bbl)	2003	2002	2001	2000	1999
Revenues	$ 38,787	$ 26,677	$ 30,406	$ 24,750	$ 6,138
Cash flow	21,217	14,677	20,717	17,890	2,015
Per share - basic	0.618	0.554	0.821	0.730	0.088
Per share - diluted	0.618	0.544	0.789	0.697	0.084
Net income	1,696	982	7,335	8,348	27
Per share - basic	0.049	0.037	0.291	0.342	0.001
Per share - diluted	0.049	0.036	0.279	0.336	0.001
Working capital (deficiency) [1]	(51,879)	(35,176)	(21,389)	(6,224)	(4,407)
Long-term debt	4,915	5,000	-	5	85
Capital expenditures, net	32,693	35,232	37,093	22,104	6,637
Property, plant and equipment	190,768	103,640	79,536	52,372	33,865
Common shares outstanding	50,090	27,641	26,513	24,569	24,797
Shareholders' equity	$ 101,567	$ 46,668	$ 44,461	$ 38,445	$ 27,002
Reserves					
Proved and probable [2] at 10% discount	$ 186,500	$ 154,500	$ 135,700	$ 154,500	$ 87,400
Oil and liquids (mbbls)	3,367	3,050	2,797	2,236	2,519
Gas (bcf)	91.1	80.1	84.0	89.1	93.5
Production					
Gas (mmcf/d)	20.15	19.56	24.46	10.71	3.68
Oil and liquids (bbls/d)	862	763	528	539	584
boe/d	4,220	4,022	4,604	2,322	1,197
Land Holdings					
Net acres (undeveloped)	329,000	189,552	116,134	52,846	39,363
Drilling (gross wells)					
Gas	21	6	14	3	2
Oil	4	4	5	–	2
Dry and abandoned	7	6	–	–	–
Total	32	16	19	3	4
Drilling (net wells)					
Gas	5.59	1.26	3.47	0.42	0.48
Oil	2.06	2.92	5.00	–	0.60
Dry and abandoned	5.79	2.12	–	–	–
Total	13.44	6.30	8.47	0.42	1.08

[1] Includes demand bank debt.

[2] Established reserves for years prior to 2003.

Note: Certain figures for prior years were restated due to the retroactive application of the change in accounting policy for asset retirement obligations pursuant to CICA S. 3110.

BOARD OF DIRECTORS

Jan M. Alston, B.A., LL.B.
President, Chief Executive Officer and Director

Bruce J. Murray, B.Comm.(2)
Chief Operating Officer and Director

John A. Niedermaier, B.Sc., P.Eng.(1) (2) (3)
Director

Owen C. Pinnell, P.Eng. (3)
Director

Harry B. Wheeler B.Sc.(1) (2)
Director

Ronald J. Will, B.Sc.(1) (3)
Chairman of the Board and Director

OFFICERS

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President and Chief Executive Officer

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Chief Operating Officer

Terry L. Lindquist, B.Comm., C.A.
Chief Financial Officer

Richard Fedoruk, M.Sc., P.Geol.
Vice President, Exploration

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Vice President, Engineering

Michael Lambros, B.A.
Vice President, Land

John Emery, B.Sc., P.Eng.
Manager of Engineering

Scott R. Seipert, CMA
Controller

Keith A. Greenfield, B.Sc., LL.B.
Corporate Secretary

(1) Member of Audit and Reserves Committee
(2) Member of Environment, Health and Safety Committee
(3) Member of Compensation Committee

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STANDARD ABBREVIATIONS

bbl	barrel
bbls/d	barrels per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
bcf	billion cubic feet
boe	barrel of oil equivalent (based on converting 6 mcf of gas to one barrel)
boe/d	barrels of oil equivalent per day
GJ	Gigajoule

Certain information included in this annual report is forward-looking and is subject to important risks and uncertainties. The results or events predicted in these statements may differ materially from actual results or events. Factors which could cause results or events to differ from current expectations include, among other things: the impact of commodity prices; well production rates; drilling success; the timing of exploration and development activities; the ability of Purcell Energy to make acquisitions and/or integrate the operations of acquired businesses in an effective manner; general industry and market conditions and growth rates; international growth and global economic conditions, including interest rate and currency exchange rate fluctuations; stock market volatility; the ability of Purcell Energy to recruit and retain qualified employees; and the successful implementation of Purcell Energy's overall business strategy. For additional information with respect to certain of these and other factors, see the reports filed by Purcell Energy with the Canadian securities regulators. Purcell Energy disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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